PROVIDENT ENERGY TRUST

Differentiation Through Diversification.

2006 Year-End and Fourth Quarter Results

All values are in Canadian dollars and conversions of natural gas volumes to barrels of oil equivalent (boe) are at 6:1 unless otherwise indicated.

Highlights

- Provident achieved record financial results again in 2006, generating cash flow of $433 million or $2.20 per unit, and a payout ratio of 66 percent. These excellent results in a volatile business environment illustrate the strength of Provident's balanced portfolio strategy.
- Full year Midstream EBITDA of $220 million caps an exceptional year for the Midstream business. Successful integration of the major NGL business acquisition that was completed late in 2005 enabled Midstream to take advantage of an excellent business environment in 2006.
- Upstream production averaged 31,700 barrels of oil equivalent per day in 2006, reflecting strong operational performance.
- Consolidated proved plus probable oil and gas reserves increased 14 percent to 153 million barrels of oil equivalent (boe). Provident's upstream reserve life index (RLI) increased for the fourth consecutive year, reaching 12.4 years and reinforcing the sustainability of the Trust. With its long-life midstream assets factored in, Provident has a total economic life index of 18.3 years.
- Through internal development and acquisition activity, Provident replaced 185 percent of total production, increasing total proved reserves to 118 million boe.
- In a year of rising industry costs, Provident delivered competitive capital efficiency performance. Finding, development and acquisition (FD&A) costs including revisions and future development capital were $22.04 per boe of proved plus probable reserves, or $13.26 over a three-year average.
- Provident executed on growth opportunities in all three business units in 2006.
    - The Trust's largest upstream acquisition to date added high quality, long-life natural gas assets in the Canadian upstream business.
    - In the U.S., a highly successful initial public offering of BreitBurn Energy Partners L.P., a new master limited partnership, sets the stage for further growth.
    - Midstream completed a new rail offloading and storage terminal at the Redwater facility, strengthening that facility's position as a service provider to the oil sands industry.

CALGARY, ALBERTA – Provident Energy Trust (Provident) (TSX-PVE.UN; NYSE-PVX) reported 2006 cash flow from operations of $433 million ($2.20/unit) compared to $311 million ($1.95/unit) generated in 2005, an increase of 39 percent. Revenue generated for the year totaled $2.2 billion, an increase of 61 percent from $1.4 billion in 2005. Distributions declared totaled $283 million ($1.44/unit) compared to $231 million ($1.44/unit) for the same period in 2005, an increase of 23 percent. The payout ratio of cash flow from operations for 2006 was 66 percent compared to 74 percent for 2005.

"We had a stellar year in 2006," said Provident President and Chief Executive Officer Tom Buchanan. "We delivered record financial results and an excellent return for our investors, even in spite of commodity price volatility, rising costs, and the announcement by the Canadian government of a proposed tax on distributions commencing in 2011. We see these results as evidence that our balanced portfolio strategy is delivering the intended long-term value and sustainability."

Provident's fourth quarter cash flow from operations was $123 million ($0.58/unit), an increase of 27 percent from $96 million ($0.57/unit) in the fourth quarter of 2005. Distributions declared in the fourth quarter were $76 million ($0.36/unit) compared to $63 million ($0.36/unit) in the same period of 2005. Provident's fourth quarter payout ratio was 62 percent, down from 65 percent in the fourth quarter 2005.

Full year net earnings for 2006 were a record $141 million, up from $97 million in 2005. For the fourth quarter of 2006, Provident recorded a net loss of $26 million, compared to net earnings of $55 million in the fourth quarter of 2005. The decline in fourth quarter net earnings is due primarily to a $56 million change in unrealized loss on financial derivative instruments. Provident's risk management program incorporates the use of financial derivative instruments, including commodity price hedges, to stabilize cash flow over time. Particularly in the Midstream business, Provident routinely enters into oil and gas futures contracts with effective periods of up to five years, to protect margins on the extraction, fractionation and sale of natural gas liquids (NGLs). Due to the accounting requirement to "mark to market" all unrealized gains and losses associated with future financial derivative instruments at a point in time and report these against current period income, Provident's net earnings show substantial quarterly variation that is not necessarily related to current operations.

Business Unit Results

Provident has three business units, Canadian Oil and Gas Production (COGP), U.S. Oil and Gas Production (USOGP), and Midstream, together providing a portfolio of diversified investments across the energy value chain in Canada and the United States.

Canada Oil and Gas Production

Provident's Canadian Oil and Gas Production (COGP) business unit produces and sells natural gas and oil from producing assets primarily in Alberta and southern Saskatchewan.

In 2006, COGP performed well operationally in an increasing cost environment. Success continued in Provident's organic shallow gas play in Southwest Saskatchewan, and a major acquisition in Northwest Alberta strengthened the Canadian asset base.

The 2006 capital program of $70 million resulted in Southwest Saskatchewan adding approximately 1,800 barrels of oil equivalent per day (boed) of natural gas production by drilling 36 wells (gross). Successful joint venture projects in West Central Alberta, and recompletions and drilling in Southern Alberta, Southeast Saskatchewan and Lloydminster also added approximately 2,500 gross boed of production.

In August 2006, Provident acquired natural gas producing assets in the Rainbow and Peace River Arch areas of Northwest Alberta for $473 million. These new assets added 5,500 boed of production and 24 million boe of proved plus probable reserves, as well as 80,000 net acres of undeveloped land. COGP's first 32-well winter drilling program in Northwest Alberta began ahead of schedule due to favourable weather conditions and was fully completed in early 2007. Testing, completions, and tie-ins are now underway.

COGP production averaged 24,000 boed in 2006 compared to 26,500 boed in 2005. Production was weighted 57 percent natural gas, 34 percent light/medium crude oil and NGLs, and nine percent conventional heavy oil. The lower production in 2006 is primarily due to a property disposition of 2,100 boed in September 2005. Natural declines were partially offset by drilling and optimization activities. For the fourth quarter of 2006, however, COGP production averaged 26,000 boed, an increase of 10 percent over the same period in 2005 as a result of the newly-acquired Northwest Alberta assets.

Operating costs for 2006 in COGP were $11.14 per boe for the full year, and $11.84 per boe in the fourth quarter. This is up from $9.86 per boe in 2005. The increase was due to industry-wide cost pressures in well servicing, maintenance, fluid hauling and fuel. Fourth quarter operating costs were also impacted by higher than expected costs for electricity. Field operating netbacks on COGP production were $24.88 per boe for the full year 2006 and $22.60 for the fourth quarter.

Financially, COGP generated $185 million of cash flow from operations, matching the $185 million generated in 2005. In the fourth quarter 2006, COGP generated $49 million cash flow from operations, down seven percent from $52 million in the same period in 2005. The slight decrease reflected the volatile commodity prices in the fourth quarter of 2006. West Texas Intermediate (WTI) crude oil prices dipped to an average of US$58.88 per bbl average for October, down from a high of US$74.41 per bbl average for July. Natural gas prices were even more volatile in the fourth quarter of 2006, with NYMEX Henry Hub natural gas reaching a low of US$4.25 per mmbtu in September, only to rebound to US$8.80 per mmbtu in the latter part of November.

U.S. Oil and Gas Production

Provident's USOGP business unit produces and sells primarily light sweet crude oil from basins in Southern California and Wyoming. Following the launch of a new publicly-traded master limited partnership (MLP) in October 2006, Provident's USOGP business unit now consists of two entities. BreitBurn Energy Partners L.P. (NASDAQ-BBEP) is the new MLP, of which Provident owns approximately 66 percent. Those assets which were not included in the MLP remain in the pre-existing 96 percent-owned, privately-held subsidiary, BreitBurn Energy Company L.P. (BreitBurn). Provident will continue to consolidate all production, financial and reserves results from both entities in the USOGP business unit, as required under both Canadian and U.S. generally accepted accounting principles (GAAP) (see the Management's Discussion & Analysis for details).

USOGP had a milestone year in 2006. The completion of the initial public offering of 6,900,000 units of the MLP in October is significant in terms of increasing access to U.S. markets, lowering the cost of capital in the U.S., and enabling direct investment by Americans in U.S. properties. Trading on NASDAQ, BBEP closed the year at US$24.10 per unit, up from the initial offering price of US$18.50 per unit. The market value of the MLP has continued to increase, closing at $27.32 on March 6, 2007.

The MLP now operates mature, stable producing assets in the Los Angeles basin and the Big Horn and Wind River basins of Wyoming. Assets with further growth potential, specifically at Orcutt and West Pico, will be retained in the pre-existing company. The MLP will have first right of offer on any assets that BreitBurn may decide to sell as additional reserves are developed. With its attractive cost of capital,

the MLP is well positioned to be Provident's primary acquisition vehicle for further upstream growth in the United States. Early in 2007, the MLP moved ahead with its growth strategy, making a small initial acquisition of long-life assets in the Permian Basin of West Texas for US$29 million.

USOGP generated cash flow from operations of $63 million in 2006, an increase of five percent over the $60 million generated in 2005. Fourth quarter cash flow from operations was $14 million, a decrease of 15 percent from the fourth quarter of 2005. The decrease was due primarily to higher general and administrative costs in 2006 driven by increased compliance costs (including the Sarbanes-Oxley Act), increased staffing levels and increased legal costs related to the initial public offering of the MLP.

Production from USOGP averaged 7,700 boed for 2006, up six percent from 7,300 boed in 2005 and was weighted 95 percent light/medium crude oil and five percent natural gas. Fourth quarter 2006 production was 7,800 boed, of which 4,600 boed was produced by the MLP.

USOGP operating costs were $18.45 per boe for the full year 2006, up from $14.82 per boe in 2005, and reached $21.74 per boe in the fourth quarter of 2006, compared with $16.49 per boe for the same quarter in 2005. Much of the U.S. production is in urban areas, and there were sharp increases for utilities and services costs in 2006. Also, the business unit returned some higher-cost wells to production to take advantage of strong crude oil prices. Netbacks remain strong in the U.S., however, averaging $37.56 per boe for the full year 2006, and $28.67 per boe for the fourth quarter.

In 2006, internal development projects achieved stable production and strong reserve replacement. The U.S. business saw particularly good results in Wyoming, where drilling and optimization projects on 27 wells added over 500 boed of production, exceeding expectations. The natural decline rates for Provident's USOGP assets are low, at an average of approximately nine percent per year. USOGP spent a total of $54 million in capital expenditures in 2006.

In the Orcutt field in California's Santa Maria basin, BreitBurn launched a heavy oil thermal recovery project. Work began on drilling eight wells for delineation and two commercial well pods, each containing 15 wells at a cost of $15 million. Test results have been encouraging. The regulatory approval process is nearing completion, and production is expected to begin late in 2007, with full production of 1,500 to 1,800 bpd to be reached by 2009.

Midstream

Provident's Midstream business unit participates in all elements of the natural gas liquids (NGL) value chain, including extraction of NGLs from natural gas, transportation, fractionation of blended NGLs into products (ethane, propane, butane and condensate), storage of blended NGLs and NGL products, and distribution and marketing of NGL products. Provident is the second largest integrated NGL player in Canada, and is one of two Canadian companies with ownership in a west-to-east NGL system.

Midstream had an outstanding year in 2006, driven by an exceptionally strong midstream business environment through most of the year. The successful integration of the major NGL business acquisition that Provident completed at the end of 2005 also contributed to the excellent results. For 2006, Midstream EBITDA (earnings before interest, taxes, depletion, depreciation, accretion and other non-cash items) was $220 million, significantly exceeding the historical averages for these businesses before they were combined in the December 2005 acquisition. The fourth quarter is typically the strongest quarter in the NGL business, and this year was no exception, as the Midstream delivered $74 million of EBITDA in the fourth quarter alone. Cash flow from operations for 2006 was $184 million in 2006 and $61 million in the fourth quarter. All of these figures are significantly higher than the 2005 results, due mainly to the acquisition.

Having fully integrated the acquired Empress-based business with its pre-existing Redwater-based business, Provident now defines three distinct business lines within the expanded Midstream business unit. These are Empress East, which generated approximately 52 percent of the total Midstream operating margin in 2006, Redwater West, which generated approximately 27 percent of the total, and Commercial Services, responsible for approximately 21 percent.

The Empress East business line includes Provident's substantial ownership of straddle plant capacity at Empress, Alberta, pipeline access to ship NGLs to central Canada, and fractionation and distribution capacity in Sarnia. The Empress East business processes natural gas, purchasing and extracting the NGLs at the Empress straddle plants and selling the specification products into markets in Ontario, Quebec and the Eastern United States. Ethane is sold on a fixed margin basis to petrochemical companies under long-term contracts. Income from the other NGL products (propane, butane and condensate) is primarily driven by the price relationship between the feedstock natural gas and NGL product prices, which are closely linked to crude oil prices. The higher the ratio between crude oil prices and natural gas prices (known as the "frac spread ratio"), the better this business line will perform. The gross margin generated by Empress East in 2006 was $133.7 million.

The key asset in the Redwater West business line is the Redwater fractionation facility near Edmonton, Alberta. Other assets include partial ownership of the Younger NGL extraction plant in Northeast British Columbia and a proprietary NGL pipeline system in Northwest Alberta. The Redwater West business buys NGL mix from various producers and transports it to Redwater for fractionation. The specification products are then sold to markets in Western Canada and the Western United States. Additional income includes the long term NGL purchase agreement from Taylor Gas Liquids for its share of the production at the Younger plant. The gross margin generated by Redwater West was $69.5 million in 2006.

The Commercial Services business line is the most stable part of the Midstream business, generating income from fee-for-service contracts to provide fractionation, storage, loading, and marketing services to upstream producers. This business line also includes pipeline tariff income from Provident's ownership in NGL pipelines. The gross margin generated by Commercial Services in 2006 was $52.8 million.

In 2006, Midstream expanded Commercial Services by completing a new condensate rail offloading facility at Redwater. A second phase of this facility will be completed early in 2007. The demand for condensate is growing along with the growth of the Alberta oil sands industry, as condensate is used to dilute bitumen for transportation in pipelines. The Redwater facility is well positioned to provide various niche services to oil sands operators.

Midstream capital expenditures in 2006 were $66 million. Only $3.5 million of that total was required for sustaining capital; the remainder was spent on growth projects.

Reserves

A combination of drilling and acquisition activity increased Provident's reserves base again in 2006, as management continues to focus on building the long-term sustainability of the Trust. Consolidated proved producing reserves increased to 89.9 million boe at year-end 2006, up from 74.6 million boe in 2005. Total consolidated proved reserves increased to 117.8 million boe from 104.0 million boe over the same period, and proved plus probable reserves grew to 153.0 million boe from 133.8 million boe a year earlier. Internal development activities successfully replaced 62 percent of total production, which is consistent with Provident's strategy of replacing reserves through a combination of internal development and acquisitions. Reserves are reported on a company share basis (see reserves disclosure for detail).

Provident's upstream Reserve Life Index at the end of 2006 increased to 12.4 years, as the Rainbow asset acquisition strengthened the reserve life of the Canadian production business. This data follows reserves reporting standards in NI 51-101. Provident also calculates a total "Economic Life Index" for the Trust, which takes into account the long-life Midstream assets. The year-end 2006 Economic Life Index increased to 18.3 years.

Provident's oil and gas operating groups also had another year of solid capital efficiency performance in 2006. Provident's consolidated 2006 finding, development and acquisition (FD&A) costs including revisions and provision for future development capital were $25.18 per boe for proved reserves and $22.04 per boe for proved plus probable reserves. On a three-year average, the FD&A costs for proved reserves were $15.15 per boe and $13.26 per boe for proved plus probable.

Government Taxation Announcement

As discussed in Provident's third quarter press release, the Canadian government made an unexpected announcement on October 31, 2006, stating its intention to introduce a substantial new 31.5 percent tax on income trust distributions beginning in 2011. This announcement caused a severe negative market reaction early in November. The government remains committed to this course of action in spite of compelling evidence of the very positive impact that energy trusts in particular have on the Canadian energy industry, on the economy in general, and on government tax revenues.

Since the original announcement, the government has also clarified the rules around the extent to which a trust is allowed to grow before 2011 without triggering immediate taxable status. A trust can double in size before 2011, and trusts can merge without penalty. This is positive, suggesting that Provident's near term business plan and growth objectives will not be impacted by the taxation announcement.

Provident remains active in the efforts to try to convince the government to modify its proposal or to exempt energy trusts. Unitholders are encouraged to contact the government to voice opposition to this proposal. Contact details and other information are available on Provident's website.

As well as working with government, management is also actively engaged in strategic planning to determine the best course of action for Provident under the proposed new tax regime. With diverse businesses and a history of innovation, the Trust is well positioned to identify creative solutions. While it will take time to fully examine all options, management remains committed to making Provident a premier energy income and growth investment.

Outlook

With a $170 million capital budget, Provident is expecting another active year in 2007. Weakening commodity prices early in the year impacted cash flow, although management is taking advantage of the stronger forward commodity prices to add some additional hedging to protect a floor level of EBITDA in each of the business units.

In the Canadian Oil and Gas Production business (COGP), Provident intends to spend $72 million across its six operating areas in 2007. Over half of that capital will be deployed on the recently-acquired assets in Northwest Alberta and the organic shallow gas play in Southwest Saskatchewan. The planned divestiture of heavy oil assets in Lloydminster that was mentioned in the third quarter press release did not take place. Provident did not receive bids of sufficient value to warrant a transaction, reflecting the uncertainty in the marketplace late in the year caused by the government taxation announcement.

Provident expects COGP production to average 22,000 to 24,000 boed in 2007. Operating costs should stay reasonably consistent with 2006 levels. In 2007, COGP will continue to focus on strengthening internal operating capability, and specifically on applying the shallow gas knowledge gained in Southwest Saskatchewan to the new natural gas assets in Northwest Alberta.

In the U.S. Oil and Gas Production business (USOGP), Provident plans to spend $53 million in 2007, a significant portion of which will be used for Orcutt and other growth opportunities. BreitBurn Energy Partners (BBEP) will continue to pursue acquisition opportunities that fit its successful business model, such as the Permian Basin acquisition that was completed early in 2007. Production is expected to average 8,000 to 8,500 boed in 2007, which includes both BBEP and the pre-existing business. These numbers assume initial production from the Orcutt heavy oil project late in 2007. Operating costs are expected to stay fairly consistent with 2006 levels, as weaker commodity prices have not yet translated into lower costs in that business.

In the Midstream, Provident plans to spend $42 million in capital expenditures in 2007, of which only $6 million is required for maintenance capital. The remainder is planned for growth projects including further expansion of the condensate rail offloading terminal and new storage caverns at Redwater.

2007 Midstream EBITDA will depend on the business environment. Thus far in the first quarter, frac spreads have weakened from their 2006 highs, and lower commodity prices have reduced product margins in absolute terms. However, propane demand has been strong in Eastern North America, effectively drawing down Provident's substantial winter propane inventories.

The remaining $3 million in capital is intended for corporate purposes. In addition, the Trust will incur one-time net expenditures of approximately $23 million in 2007 and 2008 related to a move of the Calgary head office into a new building. These expenditures will be amortized over the 14 year term of the lease. As a result of Provident's growth, employees are currently housed in two buildings, both of which are full to capacity. The planned 2008 move into Livingston Place, an office complex currently under construction, will accommodate growth and improve efficiency by consolidating all employees into a single location.

With respect to corporate priorities for 2007, Provident management will continue to develop strategy in response to the government taxation announcement in 2007, as well as evaluate acquisition opportunities that may arise as the energy trust sector adjusts to the planned tax changes. As always, Provident's primary focus is on delivering long-term value and sustainability for unitholders. In 2006, the Trust delivered a total return for investors of 13.8 percent, which was among the very best of the energy trusts in a challenging year.

Management's discussion and analysis

The following analysis provides a detailed explanation of Provident's operating results for the quarter and year ended December 31, 2006 compared to the quarter and year ended December 31, 2005 and should be read in conjunction with the consolidated financial statements of Provident. This analysis has been prepared using information available up to March 7, 2007.

Provident Energy Trust has diversified investments in certain segments of the energy value chain. Provident currently operates in three key business segments: Canadian crude oil and natural gas production ("COGP"), United States crude oil and natural gas production ("USOGP"), and midstream services and marketing ("Midstream"). Provident's COGP business produces crude oil and natural gas from six core areas in the western Canadian sedimentary basin. USOGP produces crude oil and natural gas in Southern California and in Wyoming, U.S.A. The Midstream business unit operates in Canada and the U.S.A. and extracts, processes, markets, transports and offers storage of natural gas liquids within the integrated facilities at Younger in British Columbia, Redwater and Empress in Alberta, Kerrobert in Saskatchewan, Sarnia in Ontario, Superior in Wisconsin and Lynchburg in Virginia.

This analysis commences with a summary of the consolidated financial and operating results followed by segmented reporting on the COGP business unit, the USOGP business unit and the Midstream business unit. The reporting focuses on the financial and operating measurements management uses in making business decisions and evaluating performance.

Forward-looking statements

Certain statements included in this analysis constitute forward-looking statements under applicable securities legislation. These statements relate to future events or Provident's future performance. All statements other than statements of historical fact are forward-looking statements. In some cases, forward-looking statements can be identified by terminology such as "may", "will", "should", "expect", "plan", "anticipate", "believe", "estimate", "predict", "potential", "continue", or the negative of these terms or other comparable terminology. Forward-looking statements or information in this analysis include, but are not limited to, business strategy and objectives, reserve quantities and the discounted present value of future net cash flows from such reserves, net revenue, future production levels, capital expenditures, exploration plans, development plans, acquisition and disposition plans and the timing thereof, operating and other costs, royalty rates, budgeted levels of cash distributions and the performance associated with Provident's natural gas midstream, NGL processing and marketing business. These statements are only predictions. Actual events or results may differ materially. In addition, this analysis may contain forward-looking statements attributed to third party industry sources. Undue reliance should not be placed on these forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By its nature, forward-looking information involves numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur. In addition to other assumptions identified in this analysis, assumptions in respect of forward-looking statements have been made regarding, among other things:

- Provident's ability to benefit from the combination of growth opportunities and the ability to grow through the capital markets;
- Provident's acquisition strategy, the criteria to be considered in connection therewith and the benefits to be derived therefrom;
- sustainability and growth of production and reserves through prudent management and acquisitions;
- the emergence of accretive growth opportunities;
- the ability to achieve a consistent level of monthly cash distributions;
- the impact of Canadian governmental regulation on Provident, including the effect of proposed taxation of trust distributions;
- the existence, operation and strategy of the commodity price risk management program;
- the approximate and maximum amount of forward sales and hedging to be employed;
- changes in oil and natural gas prices and the impact of such changes on cash flow after hedging;
- the level of capital expenditures devoted to development activity rather than exploration;

- the sale, farming out or development using third party resources to exploit or produce certain exploration properties;
- the use of development activity and acquisitions to replace and add to reserves;
- the quantity of oil and natural gas reserves and oil and natural gas production levels;
- currency, exchange and interest rates;
- the performance characteristics of Provident's NGL services, processing and marketing business;
- the growth opportunities associated with the NGL services, processing and marketing business; and
- the nature of contractual arrangements with third parties in respect of Provident's NGL services, processing and marketing business.

Although Provident believes that the expectations reflected in the forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Provident can not guarantee future results, levels of activity, performance, or achievements. Moreover, neither the Trust, Provident nor any other person assumes responsibility for the accuracy and completeness of the forward-looking statements. Some of the risks and other factors, some of which are beyond Provident's control, which could cause results to differ materially from those expressed in the forward-looking statements contained in this analysis include, but are not limited to:

- general economic conditions in Canada, the United States and globally;
- industry conditions associated with the NGL services, processing and marketing business;
- fluctuations in the price of crude oil, natural gas and natural gas liquids;
- uncertainties associated with estimating reserves;
- royalties payable in respect of oil and gas production;
- interest payable on notes issued in connection with acquisitions;
- income tax legislation relating to income trusts, including the effect of proposed taxation of trust distributions;
- governmental regulation in North America of the oil and gas industry, including income tax and environmental regulation;
- fluctuation in foreign exchange or interest rates;
- stock market volatility and market valuations;
- the impact of environmental events;
- the need to obtain required approvals from regulatory authorities;
- unanticipated operating events which can reduce production or cause production to be shut-in or delayed;
- failure to realize the anticipated benefits of acquisitions;
- competition for, among other things, capital reserves, undeveloped lands and skilled personnel;
- failure to obtain industry partner and other third party consents and approvals, when required;
- risks associated with foreign ownership; and
- third party performance of obligations under contractual arrangements.

Statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the resources and reserves described can be profitably produced in the future. Readers are cautioned that the foregoing list of factors is not exhaustive. The forward-looking statements contained in this analysis are expressly qualified by this cautionary statement. Subject to Provident's obligations under applicable securities laws, Provident is not under any duty to update any of the forward-looking statements after the date of this analysis to conform such statements to actual results or to changes in Provident's expectations.

Consolidated financial highlights

Consolidated ($ 000s except per unit data)	Three months ended December 31, 2006	2005	% Change	Year ended December 31, 2006	2005	% Change
Revenue (net of royalties and financial derivative instruments)	**$ 548,086**	$ 442,687	24	**$ 2,187,253**	$ 1,360,274	61
Cash flow from COGP operations [1]	**$ 48,574**	$ 51,992	(7)	**$ 185,328**	$ 185,129	-
Cash flow from USOGP operations [1]	**13,573**	16,014	(15)	**62,970**	59,821	5
Cash flow from midstream services and marketing [1]	**60,532**	28,292	114	**184,366**	66,238	178
Total cash flow from operations [1]	**$ 122,679**	$ 96,298	27	**$ 432,664**	$ 311,188	39
Per weighted average unit – basic [2]	**$ 0.58**	$ 0.57	2	**$ 2.20**	$ 1.95	13
Per weighted average unit – diluted [3]	**$ 0.58**	$ 0.51	14	**$ 2.20**	$ 1.95	13
Declared distributions to unitholders	**$ 75,573**	$ 62,646	21	**$ 283,465**	$ 230,714	23
Per unit [2]	**$ 0.36**	$ 0.36	-	**$ 1.44**	$ 1.44	-
Percent of cash flow from operations paid out as declared distributions	**62%**	65%	(5)	**66%**	74%	(12)
Net (loss) income	**$ (25,501)**	$ 54,501	-	**$ 140,920**	$ 96,926	45
Per weighted average unit – basic [2]	**$ (0.12)**	$ 0.32	-	**$ 0.72**	$ 0.61	18
Per weighted average unit – diluted [3]	**$ (0.12)**	$ 0.32	-	**$ 0.72**	$ 0.61	18
Capital expenditures	**$ 60,911**	$ 51,011	19	**$ 190,433**	$ 156,499	22
Midstream NGL acquisition	**$ (1,264)**	$ 772,303	-	**$ 1,036**	$ 772,303	(100)
Nautilus acquisition	**$ -**	$ -	-	**$ -**	$ 91,420	(100)
Property acquisitions	**$ 8,649**	$ 1,266	583	**$ 480,357**	$ 586	81,872
Property dispositions	**$ (29)**	$ 461	-	**$ (1,268)**	$ 45,100	-
Weighted average trust units outstanding (000s)						
- Basic [2]	**209,826**	169,609	24	**196,627**	159,316	23
- Diluted [3]	**210,113**	188,036	12	**196,914**	159,686	23

Consolidated ($ 000s)	As at December 31, 2006	2005	% Change
Capitalization			
Long-term debt	**$ 988,785**	$ 884,604	12
Unitholders' equity	**$ 1,542,974**	$ 1,404,826	10

[1] Represents cash flow from operations before changes in working capital and site restoration expenditures.

[2] Excludes exchangeable shares.

[3] Includes dilutive impact of unit options, exchangeable shares and convertible debentures.

Operational highlights

Consolidated	Three months ended December 31,			Year Ended December 31,		
	2006	2005	% Change	**2006**	2005	% Change
Oil and Gas Production						
Daily production						
Light/medium crude oil (bpd)	**13,899**	14,051	(1)	**14,114**	14,979	(6)
Heavy oil (bpd)	**1,838**	3,195	(42)	**2,057**	4,358	(53)
Natural gas liquids (bpd)	**1,345**	1,653	(19)	**1,419**	1,596	(11)
Natural gas (mcfd)	**100,029**	73,363	36	**84,891**	77,095	10
Oil equivalent (boed) [1]	**33,753**	31,126	8	**31,739**	33,782	(6)
Average selling price (before realized financial derivative instruments)						
Light/medium crude oil ($/bbl)	$ **54.59**	$ 55.31	(1)	$ **60.32**	$ 54.69	10
Heavy oil ($/bbl)	$ **25.82**	$ 28.62	(10)	$ **36.80**	$ 31.33	17
Corporate oil blend ($/bbl)	$ **51.23**	$ 50.36	2	$ **57.33**	$ 49.43	16
Natural gas liquids ($/bbl)	$ **47.49**	$ 49.44	(4)	$ **51.98**	$ 49.09	6
Natural gas ($/mcf)	$ **6.71**	$ 11.44	(41)	$ **6.66**	$ 8.43	(21)
Oil equivalent ($/boe) [1]	$ **45.65**	$ 57.50	(21)	$ **49.35**	$ 49.86	(1)
Field netback (before realized financial derivative instruments) ($/boe)	$ **23.96**	$ 34.63	(31)	$ **27.93**	$ 29.97	(7)
Field netback (including realized financial derivative instruments) ($/boe)	$ **25.58**	$ 28.33	(10)	$ **28.09**	$ 24.73	14
Midstream services and marketing						
Managed NGL volumes (bpd)	**145,732**	77,100	89	**153,020**	64,740	136
EBITDA (000s) [2]	$ **74,422**	$ 29,566	152	$ **219,631**	$ 70,689	211

[1] Provident reports oil equivalent production converting natural gas to oil on a 6:1 basis.

[2] EBITDA is earnings before interest, taxes, depletion, depreciation, accretion and other non-cash items.

Fourth quarter highlights

The fourth quarter highlights section provides commentary on the fourth quarter 2006 results compared to the fourth quarter of 2005. Definitions of terms used in this section, as appropriate, are defined in the year over year section of the Management's Discussion and Analysis following later in this press release.

Consolidated cash flow from operations before changes in working capital and site restoration expenditures ("Cash Flow") and cash distributions

Consolidated	Three months ended December 31,		
($ 000s, except per unit data)	**2006**	2005	% Change
Revenue, Cash Flow and Distributions			
Revenue (net of royalties and financial derivative instruments)	**$ 548,086**	$ 442,687	24
Cash flow from operations before changes in working capital and site restoration	**$ 122,679**	$ 96,298	27
Per weighted average unit - basic (1)	**$ 0.58**	$ 0.57	2
Per weighted average unit - diluted (2)	**$ 0.58**	$ 0.51	14
Declared distributions	**$ 75,573**	$ 62,646	21
Per Unit	**0.36**	0.36	-
Percent of cash flow distributed	**62%**	65%	(5)

(1) Excludes exchangeable shares.

(2) Includes the dilutive impact of unit options, exchangeable shares and convertible debentures.

Fourth quarter 2006 cash flow was $122.7 million, 27 percent above the $96.3 million of cash flow recorded in the fourth quarter of 2005. COGP 2006 fourth quarter cash flow was $48.6 million, a seven percent decrease from the $52.0 million recorded in the comparable 2005 quarter. The main drivers for the COGP decrease were the lower realized natural gas price due to the decrease in the AECO natural gas index price, and natural production declines in crude oil and liquids. The cash flow decrease was partially offset by the addition of the Rainbow assets acquired on August 31, 2006 which increased overall production compared to the 2005 fourth quarter, as well as the successful drilling programs in Southwest Saskatchewan and activities in West Central and Southern Alberta core areas. The Rainbow assets represent COGP's new core area, Northwest Alberta. The Midstream business unit added $60.5 million to fourth quarter 2006 cash flow, 114 percent above the $28.3 million recorded in the comparable 2005 quarter. This increase is attributable to the Midstream NGL Acquisition in December of 2005 and the result of increased product margins in fourth quarter 2006 over 2005. Cash flow from operations in USOGP decreased 15 percent to $13.6 million compared to cash flow of $16.0 million in the comparable 2005 quarter. Improved netbacks were more than offset by increases to cash general and administrative expense as well as higher interest expense.

Declared distributions in the fourth quarter of 2006 totaled $75.6 million, 62 percent of cash flow from operations. This compares to $62.6 million of declared distributions in fourth quarter 2005, 65 percent of cash flow from operations.

Net (loss) income

Consolidated	Three months ended December 31,		
($ 000s, except per unit data)	**2006**	2005	% Change
Net (loss) income	**$ (25,501)**	$ 54,501	-
Per weighted average unit – basic(1)	**$ (0.12)**	$ 0.32	-
Per weighted average unit – diluted(2)	**$ (0.12)**	$ 0.32	-

(1) Based on weighted average number of trust units outstanding.

(2) Based on weighted average number of trust units outstanding including the dilutive impact of the unit option plan, exchangeable shares and convertible debentures.

Net (loss) income for the fourth quarter of 2006 decreased to a loss of $25.5 million compared to $54.5 million of net income in the comparable 2005 quarter. A 36 percent increase in earnings before interest, taxes, depletion, depreciation, accretion and other non-cash items (EBITDA) due to the Midstream NGL Acquisition was more than offset by a $56.2 million change in unrealized loss on financial derivative instruments and higher depletion, depreciation and accretion (DD&A) charges as well as higher interest expense, both reflecting the larger asset base and increased capitalization due to the Midstream NGL Acquisition and the Rainbow asset acquisition.

The COGP business segment had a net loss of $8.2 million compared to 2005 fourth quarter net income of $34.9 million. The net loss in the fourth quarter of 2006 was a result of a lower EBITDA reflecting the lower realized natural gas price due to the decrease in the AECO natural gas index price combined with a $24.0 million change in unrealized loss on financial derivative instruments.

The Midstream segment recognized a net loss of $11.0 million in the fourth quarter of 2006, as compared to $24.1 million of net income in the fourth quarter of 2005. Midstream results include EBITDA of $74.4 million in 2006 as compared to $29.6 million in fourth quarter 2005. This significant improvement in EBITDA is attributable to the Midstream NGL acquisition completed in December 2005. This acquisition has extended Provident's participation in the NGL value chain through increased managed volumes. Midstream EBITDA reflects an increase in fees for services, fixed margin extraction and equity margin on marketed NGLs. The significant improvement in Midstream EBITDA is also the result of an increase in propane plus margins in 2006 over 2005. Offsetting this strong EBITDA are unrealized losses on outstanding financial derivative instruments amounting to $28.7 million for the fourth quarter of 2006 (2005 - $0.9 million gain). Under generally accepted accounting principles, these unrealized "mark-to-market" amounts, which relate to financial instruments with effective periods ranging over the next five years from 2007 through 2011, are required to be recognized in the financial statements of Provident, affecting current period net income (see "Commodity price risk management program"). In addition, higher DD&A charges of $16.6 million compared to $4.2 million in 2005, and significantly higher interest expense of $9.6 million versus $1.1 million in 2005 are the result of a larger asset base and increased capitalization due to the Midstream NGL Acquisition.

USOGP generated a net loss of $6.3 million in the fourth quarter of 2006 with a comparative net loss of $4.5 million for 2005. A five percent decrease in EBITDA, higher DD&A reflecting a fourth quarter adjustment to reserves, and higher non-cash unit based compensation were partially offset by a decrease in future tax expense of $13.9 million in the fourth quarter of 2006, compared to the fourth quarter of 2005.

Reconciliation of non-GAAP measure

The Trust calculates earnings before interest, taxes, depletion, depreciation, accretion and other non-cash items (EBITDA) within its segment disclosure. EBITDA is a non-GAAP measure. A reconciliation between EBITDA and income before taxes and non-controlling interests follows:

Consolidated EBITDA Reconciliation	Three months ended December 31,		
($ 000s)	**2006**	2005	% Change
EBITDA	$ **140,919**	$ 103,542	36
Adjusted for:			
Interest and non-cash expenses excluding unrealized (loss) gain on financial derivative instruments	**(116,392)**	(56,828)	105
Unrealized (loss) gain on financial derivative instruments	**(24,293)**	31,943	-
Income before taxes and non-controlling interests	$ **234**	$ 78,657	(100)

Taxes

Consolidated	Three months ended December 31,		
($ 000s)	**2006**	2005	% Change
Capital taxes	$ **452**	$ 1,103	(59)
Current and withholding tax expense (recovery)	**1,433**	(1,296)	-
Future income tax expense	**21,253**	23,327	(9)
	$ **23,138**	$ 23,134	-

Capital taxes in the fourth quarter totaled $0.5 million, a decrease of $0.6 million from the $1.1 million recorded in the fourth quarter of 2005. The decrease reflects an adjustment for the legislated phase-out of the large corporations tax, netted against the increase in the Saskatchewan resource surcharge that is sensitive to crude oil prices.

The current and withholding tax expense is $1.4 million in the fourth quarter of 2006 with a comparative recovery of $1.3 million in the fourth quarter of 2005. These taxes arise from Provident's U.S. based operations and reflect an increase in 2006 income subject to tax, primarily in U.S. Midstream operations.

The 2006 fourth quarter future tax expense of $21.3 million compares to an expense of $23.3 million in the fourth quarter of 2005. The future tax expense in the fourth quarter of 2006 resulted from utilizing tax pools in both Canada and the U.S.A., reflecting the increased 2006 income subject to tax, primarily in Midstream operations.

Interest expense

Consolidated	Three months ended December 31,		
($ 000s)	**2006**	2005	% Change
Interest on bank debt	$ **11,162**	$ 4,100	172
Interest on convertible debentures	**5,146**	3,651	41
Total cash interest	$ **16,308**	$ 7,751	110
Non-cash accretion expense - convertible debentures	**654**	(752)	-
Total interest including accretion on convertible debentures	$ **16,962**	$ 6,999	142

Cash interest expense increased for the quarter as compared to the same quarter in 2005 due to the increase in the overall size of Provident, with commensurate increases in debt levels. Increased debt levels are a direct result of the Midstream NGL acquisition in late 2005 and the third quarter 2006 Rainbow asset acquisition.

Commodity price risk management program

The Trust continues to execute a commodity price risk management program that is designed to limit the Trust's exposure to fluctuations in commodity prices and to protect monthly cash distributions and support the Trust's capital program. Our risk management strategy uses structures that provide a floor price while allowing upside participation in a rising commodity price market.

In accordance with the Trust's credit policy, the Trust mitigates associated credit risk by limiting financial derivative transactions to counterparties within approved credit limits.

In the Midstream business, production margins are impacted by the spread between the purchase cost of natural gas and sales price of propane, butane and condensate. Financial market liquidity may not provide sufficient or adequate opportunity to directly hedge propane, butane and condensate prices over the longer term. Prices for propane, butane and condensate historically have correlated with prices for crude oil. As a consequence, Provident has entered into natural gas and crude oil financial derivative contracts through 2011 in order to protect production margins in the Midstream business. Short term financial derivative instruments directly fixing propane and butane prices have also been executed.

Activity in the Fourth Quarter:

COGP

Year	Product	Volume (Buy)/Sell	Terms	Effective Period
2007	Crude Oil	750 Bpd	Participating Swap US $60.00 per bbl (62% above the floor price)	January 1 - December 31
		750 Bpd	Puts US $60.00 per bbl	January 1 - December 31
	Natural Gas	2,000 Gjpd	Participating Swap Cdn $7.00 per gj (max to 78% above the floor price)	January 1 - March 31
		1,500 Gjpd	Participating Swap Cdn $7.00 per gj (max to 80% above the floor price)	January 1 - March 31, November 1 - December 31
		3,000 Gjpd	Participating Swap Cdn $6.33 per gj (max to 100% above the floor price)	April 1 - October 31
		3,000 Gjpd	Participating Swap Cdn $6.33 per gj (max to 90% above the floor price)	April 1 - October 31
		6,000 Gjpd	Participating Swap Cdn $6.30 per gj (max to 95% above the floor price)	April 1 - October 31
		1,000 Gjpd	Participating Swap Cdn $6.00 per gj (max to 66% above the floor price)	April 1 - October 31
		2,000 Gjpd	Participating Swap Cdn $6.13 per gj (max to 68% above the floor price)	April 1 - October 31
		5,000 Gjpd	Puts Cdn $6.85 per gj	January 1 - December 31
		9,500 Gjpd	Puts Cdn $6.89 per gj	January 1 - March 31, November 1 - December 31
		4,000 Gjpd	Puts Cdn $6.75 per gj	November 1 - December 31

USOGP

Year	Product	Volume (Buy)/Sell	Terms	Effective Period
2007	Crude Oil	250 Bpd	US $60.00 per bbl	January 1 - December 31
		250 Bpd	Participating Swap US $55.00 per bbl (max to 84% above the floor price)	January 1 - December 31
2008	Crude Oil	2,500 Bpd	Participating Swap US $60.00 per bbl (max to 53.3% above the floor price)	July 1 - September 31
		2,000 Bpd	Participating Swap US $60.00 per bbl (avg of 59% above the floor price)	October 1 - December 31
2009	Crude Oil	2,000 Bpd	Participating Swap US $60.00 per bbl (max to 59% above the floor price)	January 1 - September 30

MIDSTREAM

Year	Product	Volume (Buy)/Sell	Terms	Effective Period
2007	Crude Oil	500 Bpd	Cdn $74.65 per bbl	April 1 - December 31
		1,750 Bpd	Cdn $73.37 per bbl	January 1 - December 31
		(6,456) Bpd	US $63.76 per bbl (4)	January 1 - March 31
		(584) Bpd	Cdn $70.91 per bbl (4)	January 1 - March 31
	Natural Gas	3,000 Gjpd	Cdn $8.28 per gj	January 1 - January 31
		(3,201) Gjpd	Cdn $7.70 per gj	January 1 - March 31
		(2,869) Gjpd	Cdn $7.84 per gj	April 1 - December 31
		(9,812) Gjpd	Cdn $7.65 per gj	January 1 - December 31
	Propane	8,143 Bpd	US $0.9648 per gallon (4) (6)	January 1 - March 31
		806 Bpd	US $0.965 per gallon (6) (8)	January 1 - February 28
		1,666 Bpd	US $0.9668 per gallon (6) (8)	January 1 - March 31
	Normal Butane	746 Bpd	US $1.1044 per gallon (4) (7)	January 1 - March 31
	Foreign Exhange		Sell US $912,500 per month @ 1.1491 (5)	January 1 - December 31
2008	Crude Oil	500 Bpd	Costless Collar US $64.00 floor, US $74.50 ceiling	January 1 - September 30
		750 Bpd	Cdn $77.55 per bbl	January 1 - June 30
		1,045 Bpd	Cdn $75.31 per bbl	July 1 - December 31
		1,750 Bpd	Cdn $75.18 per bbl	January 1 - December 31
	Natural Gas	(10,000) Gjpd	Cdn $7.96 per gj	January 1 - December 31
		(4,443) Gjpd	Cdn $8.11 per gj	January 1 - June 30
		(2,965) Gjpd	Cdn $7.94 per gj	January 1 - September 30
		(5,808) Gjpd	Cdn $7.87 per gj	July 1 - December 31
	Foreign Exchange		Sell US $974,222 per month @ 1.1255 (5)	January 1 - September 30
2009	Crude Oil	250 Bpd	Cdn $77.37 per bbl	January 1 - March 31
		500 Bpd	Cdn $77.42 per bbl	January 1 - June 30
		500 Bpd	Cdn $75.10 per bbl	July 1 - December 31
		250 Bpd	Cdn $76.70 per bbl	July 1 - September 30
		500 Bpd	Cdn $72.46 per bbl	January 1 - December 31
	Natural Gas	(2,962) Gjpd	Cdn $8.10 per gj	January 1 - June 30
		(1,481) Gjpd	Cdn $8.74 per gj	January 1 - March 31
		(2,700) Gjpd	Cdn $7.64 per gj	January 1 - December 31
		(1,481) Gjpd	Cdn $7.59 per gj	July 1 - September 30
		(2,776) Gjpd	Cdn $7.75 per gj	July 1 - December 31

MIDSTREAM, continued

Year	Product	Volume (Buy)/Sell	Terms	Effective Period
2010	Crude Oil	500 Bpd	Cdn $71.07 per bbl	January 1 - December 31
	Natural Gas	(2,700) Gjpd	Cdn $7.35 per gj	January 1 - December 31
2011	Crude Oil	250 Bpd	Cdn $66.95 per bbl	January 1 - June 30
		885 Bpd	Cdn $70.99 per bbl	January 1 - September 30
		250 Bpd	Cdn $73.35 per bbl	January 1 - October 31
		250 Bpd	Cdn $72.75 per bbl	January 1 - November 30
		250 Bpd	Costless Collar US $60.00 floor, US $68.10 ceiling	July 1 - September 30
		250 Bpd	Costless Collar US $60.00 floor, US $67.30 ceiling	July 1 - September 30
		500 Bpd	Costless Collar US $56.00 floor, US $75.25 ceiling	July 1 - September 30
		500 Bpd	Costless Collar US $58.00 floor, US $76.20 ceiling	July 1 - September 30
		500 Bpd	Costless Collar US $60.00 floor, US $71.60 ceiling	July 1 - September 30
	Natural Gas	(1,410) Gjpd	Cdn $7.12 per gj	January 1 - June 30
		(13,269) Gjpd	Cdn $6.72 per gj	July 1 - September 30
		(4,955) Gjpd	Cdn $7.02 per gj	January 1 - September 30
		(1,481) Gjpd	Cdn $7.25 per gj	January 1 - October 31
		(1,481) Gjpd	Cdn $7.24 per gj	January 1 - November 30
	Foreign Exchange		Sell US $717,600 per month @ 1.0931 [5]	July 1 - September 30

[1] The above table represents a number of transactions entered into over an extended period of time.
[2] Natural gas contracts settle against AECO monthly index.
[3] Crude oil contracts settle against NYMEX (New York Mercantile Exchange) WTI (West Texas Intermediate) calendar average.
[4] Conversion of Crude Oil BTU (British Thermal Unit) hedges to Propane
[5] US dollar hedge contracts settled against Bank of Canada noon rate average.
[6] Propane contracts are settled against Belvieu C3 TET (Texas Eastern Transmission)
[7] Normal Butane contracts are settled against Belvieu NC4 NON-TET
[8] Midstream Inventory Hedges

Settlement of commodity contracts

The following is a summary of the net cash flow to settle Commodity contracts during the fourth quarter of 2006. For comparative purposes, the 2005 amounts are also summarized.

a) Crude oil

For the quarter ending December 31, 2006, Provident received $1.3 million (2005 - $16.5 million paid) to settle various oil market based contracts on an aggregate volume of 0.7 million barrels (2005 – 0.6 million barrels). As at December 31, 2006 the estimated value of contracts in place if settled at December 31 market prices would have resulted in an opportunity gain of $7.2 million (2005 - $7.1 million opportunity cost).

b) Natural Gas

For the quarter ending December 31, 2006, Provident received $3.7 million (2005 - $4.1 million paid) to settle various natural gas market based contracts on an aggregate volume of 3.7 million gj's (2005 – 1.5 million gj's). As at December 31, 2006 the estimated value of contracts in place if settled at December 31 market prices would have resulted in an opportunity gain of $8.6 million (2005 – $6.5 million opportunity cost).

c) Midstream

For the quarter ending December 31, 2006 Provident received $5.4 million (2005 - $1.7 million paid) on midstream margin hedging activities. As at December 31, 2006 the estimated value of contracts in place settled at December 31 market prices would have resulted in an opportunity cost of $68.8 million (2005 – $0.4 million). This value represents our five year hedging plan for Midstream executed in 2006.

d) Foreign exchange contracts

As at December 31, 2006 the estimated value of contracts in place settled at December 31 foreign exchange rates would have resulted in an opportunity gain of $0.1 million (2005 – $0.1 million opportunity cost). The foreign exchange gains have been included as a component of foreign exchange gain and other and allocated to their respective business segments.

Provident's Commodity Price Risk Management activities are also discussed in the year over year section of Management's Discussion and Analysis and in Note 14 to the consolidated financial statements.

COGP segment review

Crude oil price and liquids

COGP	Three months ended December 31,		
($ per bbl)	**2006**	2005	% Change
Oil per barrel			
WTI (US$)	**$ 60.21**	$ 60.02	-
Exchange rate (from US$ to Cdn$)	**1.14**	1.17	(3)
WTI expressed in Cdn$	**$ 68.64**	$ 70.22	(2)
Realized pricing before financial derivative instruments			
Light/Medium oil	**$ 51.93**	$ 52.28	(1)
Heavy oil	**$ 25.82**	$ 28.62	(10)
Natural gas liquids	**$ 47.46**	$ 49.62	(4)
Crude oil and natural gas liquids	**$ 46.39**	$ 45.44	2

The above prices are net of transportation expense.

In the fourth quarter of 2006 COGP's realized oil and natural gas liquids price, prior to the impact of financial derivative instruments, increased by two percent to $46.39 per barrel compared to $45.44 per barrel in the fourth quarter of 2005. The 2006 increase in total liquids mix was related to lower conventional heavy oil volumes as a percentage of the total mix, resulting in a higher proportion of production from light/medium oil, which has a higher average price than heavy oil. This was partially offset by a stronger Canadian dollar and wider differentials on heavy oil pricing relative to WTI.

Natural gas price

COGP	Three months ended December 31,		
($ per mcf)	**2006**	2005	% Change
AECO monthly index (Cdn$) per mcf	**$ 6.36**	$ 11.67	(46)
Corporate natural gas price per mcf before financial derivative instruments (Cdn$)	**$ 6.73**	$ 11.40	(41)

The above prices are net of transportation expense.

COGP's fourth quarter 2006 realized natural gas price, prior to the impact of financial derivative instruments, decreased 41 percent as compared to the fourth quarter of 2005, less than the decrease in the benchmark AECO index price of 46 percent. Provident's gas portfolio includes aggregator contracts sold on a term basis that can differ from the benchmark price and sells to the spot market on monthly or daily indices and receives prices which take into account heat content. Provident's realized prices and changes in prices can therefore differ from benchmark indices.

Production

COGP	Three months ended December 31,		
	2006	2005	% Change
Daily production			
Crude oil - Light/Medium (bpd)	**6,569**	6,866	(4)
- Heavy (bpd)	**1,838**	3,195	(42)
Natural gas liquids (bpd)	**1,331**	1,617	(18)
Natural gas (mcfd)	**97,489**	71,168	37
Oil equivalent (boed) [1]	**25,986**	23,539	10

[1] Provident reports equivalent production converting natural gas to oil on a 6:1 basis.

Production increased 10 percent to 25,986 boed during the fourth quarter of 2006 as compared to 23,539 boed in 2005. The increase was primarily a result of the additional production from the Rainbow assets acquired on August 31, 2006 and the successful drilling programs in Southwest Saskatchewan and activities in West Central and Southern Alberta core areas. Plant restrictions and down time due to cold weather at Northwest Alberta's Rainbow and Pouce Coupe fields resulted in 550 boed less production than expected in the fourth quarter of 2006. The overall increase in production was partially offset by the natural production declines including higher declines in heavy oil partially offset by drilling and optimization activities. Provident's production risk is mitigated by not having any single property providing greater than 10 percent of its total production.

Production for the fourth quarter of 2006 was weighted 63 percent natural gas, 30 percent medium/light crude oil and natural gas liquids and seven percent heavy oil. This compared to fourth quarter 2005 production weighted 50 percent natural gas, 36 percent medium/light oil and natural gas liquids and 14 percent heavy oil. Quarter-over-quarter, the change in mix reflected the Rainbow assets acquired on August 31, 2006 which was primarily natural gas production, increased capital spending on natural gas opportunities and natural production declines in the heavy oil areas.

COGP's production summarized by core areas is as follows:

COGP

Three months ended December 31, 2006	West Central Alberta	Southern Alberta	Northwest Alberta	Southeast Saskatchewan	Southwest Saskatchewan	Lloydminster	Other	**Total**
Daily production								
Crude oil - Light/Medium (bpd)	1,051	2,172	149	1,602	318	1,245	32	**6,569**
- Heavy (bpd)	-	-	-	-	-	1,838	-	**1,838**
Natural gas liquids (bpd)	1,111	101	94	-	-	22	3	**1,331**
Natural gas (mcfd)	32,913	22,494	26,928	152	13,364	1,347	291	**97,489**
Oil equivalent (boed) (1)	7,648	6,022	4,731	1,627	2,545	3,330	83	**25,986**

COGP

Three months ended December 31, 2005	West Central Alberta	Southern Alberta	Northwest Alberta	Southeast Saskatchewan	Southwest Saskatchewan	Lloydminster	Other	Total
Daily production								
Crude oil - Light/Medium (bpd)	1,057	2,541	-	1,726	337	1,204	1	6,866
- Heavy (bpd)	-	-	-	-	-	3,195	-	3,195
Natural gas liquids (bpd)	1,418	179	-	-	1	19	-	1,617
Natural gas (mcfd)	38,343	22,722	-	196	8,916	978	13	71,168
Oil equivalent (boed) (1)	8,865	6,507	-	1,759	1,824	4,581	3	23,539

(1) Provident reports equivalent production converting natural gas to oil on a 6:1 basis.

Internal development activities included 22.0 net wells drilled during the quarter ended December 31, 2006 with a 100 percent success rate as Provident continues with the expanded drilling program announced with the second quarter results. Provident's most active area in fourth quarter 2006 was southern Saskatchewan, where 12.0 net wells were drilled and focused on the shallow gas drilling program. Southern Alberta continued with its shallow gas drilling resulting in 2.1 net wells drilled. Production results to date have been strong in southern Alberta and Saskatchewan, exceeding internal expectations. Provident expects the production from the above net drills to be placed on production during the first and second quarters of 2007. Northwest Alberta's activities continued to focus on preparation for the winter drilling program and also drilled 5.4 net wells in 2006. Northwest Alberta was ahead of its planned winter drilling schedule due to effective planning and execution of the drilling program and favourable weather conditions. In Lloydminster, Provident is working to enhance the area cost structure through production optimization and increased water disposal capacity. In west central Alberta, Provident continues with its strategy of farming out high risk exploration land to enhance cash flow and drilled 2.3 net wells in low risk areas. The production in west central Alberta requires relatively less capital to manage its decline. In the majority of Provident's operated fields, fewer weather-related disruptions were experienced than historically.

Revenue and royalties

COGP ($ 000s except per boe and mcf data)	Three months ended December 31, 2006	 2005	 % Change
Oil			
Revenue	**$ 35,754**	$ 41,440	(14)
Realized loss on financial derivative instruments	**(653)**	(11,651)	(94)
Royalties (net of ARTC)	**(6,651)**	(8,969)	(26)
Net revenue	**$ 28,450**	$ 20,820	37
Net revenue (per barrel)	**$ 36.78**	$ 22.49	64
Royalties as a percentage of revenue	**18.6%**	21.6%	
Natural gas			
Revenue	**$ 60,337**	$ 74,623	(19)
Realized gain (loss) on financial derivative instruments	**3,802**	(1,521)	-
Royalties (net of ARTC)	**(11,680)**	(15,503)	(25)
Net revenue	**$ 52,459**	$ 57,599	(9)
Net revenue (per mcf)	**$ 5.85**	$ 8.80	(34)
Royalties as a percentage of revenue	**19.4%**	20.8%	
Natural gas liquids			
Revenue	**$ 5,811**	$ 7,382	(21)
Royalties	**(1,229)**	(2,013)	(39)
Net revenue	**$ 4,582**	$ 5,369	(15)
Net revenue (per barrel)	**$ 37.42**	$ 36.09	4
Royalties as a percentage of revenue	**21.1%**	27.3%	
Total			
Revenue	**$ 101,902**	$ 123,445	(17)
Realized gain (loss) on financial derivative instruments	**3,149**	(13,172)	-
Royalties (net of ARTC)	**(19,560)**	(26,485)	(26)
Net revenue	**$ 85,491**	$ 83,788	2
Net revenue per boe	**$ 35.76**	$ 38.69	(8)
Royalties as a percentage of revenue	**19.2%**	21.5%	

Note: the above revenue, net revenue and net revenue per boe figures are presented net of transportation expense.

Quarter over quarter, 2006 COGP production revenue was $101.9 million, a decrease of 17 percent from $123.4 million in 2005. The decrease in revenue is a result of a 41 percent decrease in Provident's realized natural gas price due to the decrease in the AECO natural gas index price offset by higher overall production resulting from the addition of the Rainbow assets acquired on August 31, 2006. Total royalties as a percentage of revenue decreased to 19.2 percent primarily due to a reduction in rates from capital spending incentives. The preceding factors, as well as the change in realized gain of financial derivative instruments account for net revenue of $85.5 million in the fourth quarter of 2006, two percent above the $83.8 million recorded in the fourth quarter of 2005. Net revenue per boe in the fourth quarter of 2006 was $35.76 per boe, a decrease of eight percent from $38.69 per boe in the fourth quarter of 2005. The per boe decrease was a result of the preceding factors.

Production expenses

COGP ($ 000s, except per boe data)	Three months ended December 31, 2006	 2005	 % Change
Production expenses	**$ 28,302**	$ 23,437	21
Production expenses (per boe)	**$ 11.84**	$ 10.82	9

Fourth quarter 2006 production expenses increased 21 percent to $28.3 million from $23.4 million in the comparable 2005 quarter due to increased production volumes primarily as a result of the Rainbow acquisition. However, on a boe basis quarter over quarter production expenses have increased by nine percent to $11.84 per boe from $10.82 per boe in the comparable 2005 quarter. Cost increases included higher than expected costs for

electricity and adjustments related to prior periods by operators on non-operated properties. In addition, costs have increased in fuel, chemicals, well servicing, maintenance and fluid hauling to reflect higher commodities prices and labour costs.

Operating netback

COGP	Three months ended December 31,		
($ per boe)	**2006**	2005	% Change
Netback per boe			
Gross production revenue	**$ 42.62**	$ 57.00	(25)
Royalties (net of ARTC)	**(8.18)**	(12.23)	(33)
Operating costs	**(11.84)**	(10.82)	9
Field operating netback	**$ 22.60**	$ 33.95	(33)
Realized gain (loss) on financial derivative instruments	**1.32**	(6.08)	-
Operating netback after realized financial derivative instruments	**$ 23.92**	$ 27.87	(14)

COGP operating netbacks have transportation expense netted against gross production revenue.

The fourth quarter 2006 field operating netback of $22.60 per boe was 33 percent below the $33.95 per boe in the comparable quarter in 2005. The field operating netback reflects COGP's lower realized price for natural gas and increased operating costs combined with a shift in COGP's production mix to include more natural gas. Royalties, which are price sensitive, decreased by 33 percent on a boe basis reflecting the lower prices, prior to the impact of hedging. The fourth quarter 2006 operating netback after financial derivative instruments decreased by 14 percent to $23.92 from $27.87 reflecting the preceding factors as well as the 2006 fourth quarter gains on financial derivative instruments of $1.32 per boe compared to a loss of $6.08 per boe in the comparable quarter in 2005.

General and administrative

COGP	Three months ended December 31,		
($ 000s, except per boe data)	**2006**	2005	% Change
Cash general and administrative	**$ 6,410**	$ 3,727	72
Non-cash unit based compensation	**1,182**	1,885	(37)
	$ 7,592	$ 5,612	35
Cash general and administrative (per boe)	**$ 2.68**	$ 1.72	56

Cash general and administrative expenses for COGP in the fourth quarter increased 72 percent to $6.4 million from $3.7 million recorded in the 2005 comparable quarter. On a boe basis the cash general and administrative expenses recorded in fourth quarter 2006 increased 56 percent to $2.68 from $1.72 in the fourth quarter of 2005. The increase in cash general and administrative expenses reflects additional costs associated with a more competitive landscape affecting the cost of hiring and compensating employees and consultants, as well as increases in rent, insurance and compliance and reporting costs, including costs relating to implementation of procedures and documentation in connection with the U.S. Sarbanes-Oxley Act.

COGP operations are capable of absorbing additional production, particularly in existing core areas, with little impact on cash general and administrative expenses.

Capital expenditures

COGP	Three months ended December 31,	
($ 000s)	2006	2005
Capital expenditures - by area		
West central Alberta	$ 3,968	$ 2,282
Southern Alberta	3,000	4,977
Northwest Alberta	4,598	-
Southeast Saskatchewan	384	1,006
Southwest Saskatchewan	4,006	10,925
Lloydminster	1,738	2,497
Office and other	581	(13)
Total additions	$ 18,275	$ 21,674
Capital expenditures - by category		
Geological, geophysical and land	$ 1,067	$ 141
Drilling, recompletions, and workovers	14,988	12,006
Facilities and equipment	1,365	9,449
Other capital	855	78
Total additions	$ 18,275	$ 21,674
Property acquisitions	$ 8,649	$ 1,266
Property dispositions	$ (29)	$ 461

In the fourth quarter of 2006, Provident's COGP business unit spent $18.3 million on capital expenditures. COGP spent $4.6 million in the new area, Northwest Alberta, primarily on drilling activities associated with the winter drilling program which was ahead of schedule due to favourable weather conditions and advanced planning. In the Southeast and Southwest Saskatchewan core areas $4.4 million was spent primarily on shallow gas drilling. Facility work ($0.3 million) in the area focused on infrastructure to tie-in future shallow gas production in Southwest Saskatchewan. In Southern Alberta $3.0 million was spent on drilling activities and recompletions ($2.3 million) and mineral rights acquisitions ($0.6 million). In West central Alberta $4.0 million was spent largely on non-operated drilling ($2.6 million) and facility work ($0.8 million). In the Lloydminster core area $1.7 million was spent primarily on drilling and recompletion activities.

In the fourth quarter of 2006, COGP also spent $8.6 million on property acquisitions primarily on acquiring additional working interests in Northwest Alberta ($6.7 million) and in Southern Alberta ($1.7 million).

Provident's COGP business unit spent $21.7 million in the fourth quarter of 2005 on various drilling, re-completing, optimization and facility projects.

Depletion, depreciation and accretion (DD&A)

COGP	Three months ended December 31,		
($ 000s, except per boe data)	2006	2005	% Change
DD&A	$ 58,617	$ 33,809	73
DD&A (per boe)	$ 24.52	$ 15.61	57

The COGP DD&A rate of $24.52 per boe for the fourth quarter of 2006 increased by 57 percent compared to $15.61 per boe for the fourth quarter of 2005. The increase was primarily as a result of the Rainbow asset acquisition. Additions to property, plant and equipment of $660.4 million for the acquisition include $185.7 million due to the recording of future income taxes. This, combined with higher net per boe reserve acquisition costs, resulted in increased per boe DD&A.

Accretion expense associated with asset retirement obligations was $0.5 million in the fourth quarter of 2006 compared to $0.5 million in the fourth quarter of 2005.

USOGP Segment Review

The USOGP business unit incorporates activities from certain Provident subsidiaries comprising an oil and gas exploitation and production organization based in Los Angeles, California.

In the fourth quarter of 2006, Provident, through its USOGP subsidiaries, completed its initial public offering ("IPO") of 6.9 million units at U.S. $18.50 per unit of BreitBurn Energy Partners, L.P. (the "MLP"). This master limited partnership (NASDAQ-BBEP) is a U.S. public, tax flow-through entity similar to Canadian royalty and income trusts such as Provident. Selected producing assets in the Los Angeles basin in California and in Wyoming were transferred to the MLP. The MLP operates approximately two-thirds of existing USOGP production and approximately one-half of USOGP reserves. The previously existing subsidiary ("BreitBurn") continues to operate some Los Angeles basin assets at West Pico and the Orcutt field (which is the site of the steam-assisted diatomite pilot project). At December 31, 2006 the Trust indirectly owns approximately 66 percent of the MLP and 96 percent of BreitBurn. The MLP and BreitBurn continue to be managed by the management team which operated the USOGP business unit prior to the IPO. The USOGP segment includes the consolidated results of the MLP and BreitBurn. Non-controlling interests include the public ownership in the MLP, the ownership interests of the managers in the MLP and BreitBurn, as well as third party investment in USOGP's land development project which commenced in the second quarter of 2006.

USOGP Pricing

USOGP	Three month ended December 31, 2006	2005	% Change
Realized pricing before financial derivative instruments			
Light/medium crude oil and natural gas liquids (Cdn$ per bbl)	$ **56.96**	$ 58.11	(2)
Natural gas (Cdn$ per mcf)	$ **5.87**	$ 12.97	(55)

The majority of USOGP oil production is light, sweet crude that attracts smaller differentials to benchmark prices relative to heavier blends. Realized crude oil and natural gas liquids pricing before financial derivative instruments in the fourth quarter of 2006 was comparable with the fourth quarter of 2005. WTI in the fourth quarter of 2006 was U.S. $60.21 compared to U.S. $60.02 in the fourth quarter of 2005. Oil production from the Wyoming properties is a heavier blend of crude oil that attracts wider differentials from WTI pricing. Production from Wyoming properties represents approximately 32 percent of fourth quarter 2006 production.

Realized natural gas pricing saw a 55 percent decrease to $5.87 per mcf in the fourth quarter of 2006 when compared to the fourth quarter of 2005. Natural gas represents approximately five percent of total boe production of USOGP.

Production

USOGP	Three months ended December 31, 2006	2005	% Change
Daily production - by product			
Crude oil - Light/Medium (bpd)	**7,330**	7,185	2
Natural gas liquids (bpd)	**14**	36	(61)
Natural gas (mcfd)	**2,540**	2,195	16
Oil equivalent (boed) [1]	**7,767**	7,587	2

[1] Provident reports equivalent production converting natural gas to oil on a 6:1 basis.

USOGP	Three months ended December 31, 2006	2005	% Change
Daily Production - by area (boed) [1]			
Los Angeles	**3,772**	3,974	(5)
Santa Maria - Orcutt	**1,528**	1,356	13
Wyoming	**2,467**	2,257	9
	7,767	7,587	2

[1] Provident reports equivalent production converting natural gas to oil on a 6:1 basis.

USOGP production increased 180 boe per day or two percent in the fourth quarter of 2006 when compared to the fourth quarter of 2005. The increase is primarily attributable to successful optimization and drilling projects partially offset by the low natural declines that reflect the long life nature of these assets.

Revenue and royalties

The following table outlines USOGP revenue and royalties by product line. The table excludes revenues earned from operating certain properties ($0.2 million in 2006 and $0.3 million in 2005) on behalf of third parties.

USOGP	Three months ended December 31,		
($ 000s, except per boe and mcf amounts)	**2006**	2005	% Change
Oil			
Revenue	**$ 38,546**	$ 38,583	-
Realized gain (loss) on financial derivative instruments	**1,892**	(4,875)	-
Royalties	**(3,771)**	(3,703)	2
Net revenue	**$ 36,667**	$ 30,005	22
Net revenue (per bbl)	**$ 54.37**	$ 45.39	20
Royalties as a percentage of revenue	**9.8%**	9.6%	
Natural gas			
Revenue	**$ 1,373**	$ 2,620	(48)
Royalties	**(184)**	(370)	(50)
Net revenue	**$ 1,189**	$ 2,250	(47)
Net revenue (per mcf)	**$ 5.09**	$ 11.14	(54)
Royalties as a percentage of revenue	**13.4%**	14.1%	
Natural gas liquids			
Revenue	**$ 64**	$ 135	(53)
Royalties	**(2)**	(3)	(33)
Net revenue	**$ 62**	$ 132	(53)
Net revenue (per bbl)	**$ 48.14**	$ 40.06	20
Royalties as a percentage of revenue	**3.1%**	2.1%	
Total			
Revenue	**$ 39,983**	$ 41,338	(3)
Realized gain (loss) on financial derivative instruments	**1,892**	(4,875)	-
Royalties	**(3,957)**	(4,076)	(3)
Net revenue	**$ 37,918**	$ 32,387	17
Net revenue (per boe)	**$ 53.06**	$ 46.40	14
Royalties as a percentage of revenue	**9.9%**	9.9%	

Total production revenue for the fourth quarter of 2006 was $40.0 million or three percent lower than the $41.3 million of revenue in the fourth quarter of 2005. The decrease was primarily driven by lower realized natural gas prices in the fourth quarter of 2006 when compared to the fourth quarter of 2005. Total net revenue increased $5.5 million or 17 percent in the fourth quarter of 2006 compared to the fourth quarter of 2005 primarily driven by a $6.8 million positive change in realized gains on financial derivative instruments.

Production expenses

USOGP	Three months ended December 31,		
($ 000s, except per boe amounts)	**2006**	2005	% Change
Production expenses	**$ 15,534**	$ 11,510	35
Production expenses (per boe)	**$ 21.74**	$ 16.49	32

Production expenses increased 35 percent to $15.5 million in the fourth quarter of 2006 compared to $11.5 million for the comparable quarter in 2005. Operating costs per boe have increased 32 percent to $21.74 in the fourth

quarter of 2006 from $16.49 in the comparable quarter in 2005. This change reflects both the increase in utilities and other costs and services driven by the high commodity price environment as well as higher operating cost crude oil wells that were returned to production to take advantage of high crude oil prices.

Operating netback

USOGP	Three months ended December 31,		
($ per boe)	**2006**	2005	% Change
Netback per boe			
Gross production revenue	**$ 55.95**	$ 59.22	(6)
Royalties	**(5.54)**	(5.84)	(5)
Operating costs	**(21.74)**	(16.49)	32
Field Operating Netback	**$ 28.67**	$ 36.89	(22)
Realized gain (loss) on financial derivative instruments	**2.65**	(6.98)	-
Operating netback after realized financial derivative instruments	**$ 31.32**	$ 29.91	5

The fourth quarter 2006 field operating netback of $28.67 per boe was 22 percent below the $36.89 per boe in the comparable quarter of 2005. The reduction reflects lower realized natural gas prices and increased operating costs. The fourth quarter 2006 operating netback after realized financial derivative instruments of $31.32 per boe is five percent higher than the $29.91 per boe for the fourth quarter of 2005 reflecting the preceding factors offset by realized gains on financial derivative instruments.

General and administrative

USOGP	Three months ended December 31,		
($ 000s, except per boe amounts)	**2006**	2005	% Change
Cash general and administrative	**$ 6,839**	$ 4,525	51
Non-cash unit based compensation	**7,800**	2,000	290
	$ 14,639	$ 6,525	124
Cash general and administrative (per boe)	**$ 9.57**	$ 6.48	48

Cash general and administrative expenses in the fourth quarter of $6.8 million or $9.57 per boe is 51 percent higher than the fourth quarter of 2005. The increase is due to increased costs associated with compliance (including costs associated with the implementation of procedures and documentation to be in compliance with the U.S. Sarbanes-Oxley Act), increased corporate general and administrative allocations to USOGP operations and increased staffing levels, as well as legal and consulting costs in connection with the initial public offering of the MLP.

Non-cash unit based compensation expense was $7.8 million in the fourth quarter of 2006 compared to $2.0 million in the fourth quarter of 2005. The increase in incentive plan costs is primarily driven by the initial public offering of the MLP completed in the fourth quarter of 2006.

Capital expenditures

USOGP	Three months ended December 31,			
($ 000s)		2006		2005
Capital expenditures - by category				
Geological, geophysical and land	$	**104**	$	409
Drilling, recompletions, and workovers		**6,796**		5,169
Facilities and equipment		**5,365**		5,802
Other capital		**2,049**		144
Total additions	$	**14,314**	$	11,524
Capital expenditures - by area (boed)				
Los Angeles		**2,631**		6,125
Santa Maria - Orcutt		**7,378**		2,122
Wyoming		**2,157**		2,718
Other capital		**2,148**		559
		14,314		11,524
Property acquisitions	$	-	$	-
Property dispositions	$	-	$	-

USOGP capital expenditures for the fourth quarter of 2006 totaled $14.3 million. Of this total, $9.1 million was directed at drilling, optimization and facility upgrades at West Pico, Santa Fe Springs and Orcutt. $2.2 million was directed at drilling and optimization work in Wyoming. $1.3 million was directed at optimization projects at smaller fields as well as head office related capital expenditures and $1.7 million was directed at a real estate development project initiated in the second quarter.

Depletion, depreciation and accretion (DD&A)

USOGP	Three months ended December 31,				
($ 000s, except per boe amounts)		2006		2005	% Change
DD&A	$	**9,269**	$	6,622	40
DD&A (per boe)	$	**12.97**	$	9.49	37

The USOGP's DD&A rate is low due to the long-lived nature of the assets.

On a per boe basis the DD&A rate is up $3.48 or 37 percent from the fourth quarter of 2005. This is primarily associated with a year-end depletion rate adjustment reflecting 2006 capital expenditures as well as changes in reserves.

Midstream services and marketing business segment review

Midstream NGL acquisition

The $773 million Midstream NGL Acquisition, which closed on December 13, 2005, included NGL extraction plants, pipelines, storage and fractionation facilities, distribution facilities, and contracts including marketing, supply and transportation arrangements, and NGL marketing infrastructure. This acquisition has extended Provident's involvement in the NGL value chain. Results in 2005 included NGL fee for service, fixed margin extraction, equity margin on marketed NGLs, and margin on crude oil marketing contracts. The crude oil marketing contracts were disposed in May 2005, thus 2006 results include an increase in fees for services, fixed margin extraction and equity margin on marketed NGLs.

Operations – managed NGL volumes

Provident managed 145,732 bpd over the fourth quarter of 2006, an 89 percent increase over the 77,100 bpd managed in the fourth quarter of 2005. Managed volumes are NGL products that have been purchased or received for further processing and/or sale. The significant increase in 2006 is a result of the Midstream NGL Acquisition.

Revenues

For the fourth quarter of 2006 product sales and services revenues were $441.8 million (2005 - $295.6 million). Revenue figures are after elimination of intersegment transactions. The significant increase in revenue over 2005 is a result of the Midstream NGL Acquisition, and the commissioning of the condensate loading and terminalling facilities in the second quarter of 2006. Product sales relate to the marketing of NGLs and transportation and fractionation contracts (T&F), while service revenue relates to fees earned through NGL processing, marketing, storage and distribution. The majority of NGL revenues are earned pursuant to both long-term contracts and annual evergreen purchase and sales commitments.

In addition to the increased product sales and service revenue, Midstream revenue was increased by $5.4 million in the fourth quarter of 2006 (2005 – $2.6 million loss) due to realized gains on financial derivative instruments. Midstream enters into derivative contracts to assist with margin stabilization on marketed products.

Expenses

The cost of goods sold (COGS) was $360.0 million for the fourth quarter of 2006 (2005 - $245.0 million). Cost of goods sold relates to NGL product sales revenue included in product sales and services revenue. COGS include all costs incurred in the production and purchase of NGL specification product for sale. The majority of the natural gas liquids are purchased pursuant to long-term contracts and annual evergreen purchase commitments. The significant increase in COGS over 2005 is a result of the Midstream NGL Acquisition which has resulted in an increased level of activity.

Operating and maintenance expenses were $3.1 million for the fourth quarter of 2006 (2005 - $11.7 million). Fourth quarter 2006 costs include operating costs incurred to process NGLs, and to provide T&F and storage and distribution services to third parties. In prior quarters, operating costs also included costs incurred at the Younger and Redwater facilities for Provident's own production. These costs are now included in the determination of inventory and cost of goods sold, reflecting the integration of operations after the Midstream NGL Acquisition.

General and administrative expenses were $10.5 million for the fourth quarter of 2006 (2005 - $6.8 million) representing increased costs for compliance activities including costs related to implementation of procedures and documentation in connection with the U.S. Sarbanes-Oxley Act and an increased number of employees since the Midstream NGL Acquisition. Interest expense for the fourth quarter of 2006 was $9.6 million (2005 - $1.1 million) reflecting an increase in capitalization associated with the Midstream NGL Acquisition. Depreciation expense was $16.6 million for the three months ended December 31, 2006 (2005 – $4.2 million) reflecting the larger asset base acquired through the Midstream NGL Acquisition and a $5.8 million impairment write down of capitalized inventory.

Earnings before interest, taxes, depletion, depreciation, accretion, and other non-cash items ("EBITDA") and cash flow from operations

Fourth quarter 2006 EBITDA of $74.4 million increased $44.8 million or 152 percent from $29.6 million in the fourth quarter of 2005. Cash flow for the fourth quarter of 2006 was $60.5 million, an increase of $32.2 million or 114 percent above the $28.3 million for the fourth quarter 2005. Through the Midstream NGL Acquisition, Provident has expanded its participation in the NGL value chain, which has made a significant contribution to the overall increase in EBITDA and cash flow. In addition, Midstream EBITDA and cash flow benefited from an increase in product margin in the fourth quarter of 2006 over the comparable quarter in 2005.

Management uses EBITDA to analyze the operating performance of the Midstream business unit. EBITDA as presented does not have any standardized meaning prescribed by Canadian GAAP and therefore it may not be comparable with the calculation of similar measures for other entities. EBITDA as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP. All references to EBITDA throughout this report are based on earnings before interest, taxes, depletion, depreciation, accretion, and other non-cash items ("EBITDA").

Capital expenditures

Midstream capital expenditures for the fourth quarter of 2006 totaled $28.3 million. $6.0 million of the capital was spent on the new condensate offloading facilities and truck terminals at Redwater. An additional $9.2 million was spent on the initial drilling of two new Redwater storage caverns expected to be completed in 2009. $11.3 million was also spent to acquire an additional 7.5% interest in the Provident Empress NGL Extraction plant. The remaining $1.8 million relates to sustaining capital requirements.

2006 Year end results

Consolidated cash flow from operations before changes in working capital and site restoration expenditures ("Cash Flow") and cash distributions

Consolidated	Year ended December 31,		
($ 000s, except per unit data)	**2006**	2005	% Change
Revenue, Cash Flow and Distributions			
Revenue (net of royalties and financial derivative instruments - see Note 8 to the consolidated financial statements)	$ **2,187,253**	$ 1,360,274	61
Cash flow from operations before changes in working capital and site restoration expenditures	$ **432,664**	$ 311,188	39
Per weighted average unit - basic (1)	$ **2.20**	$ 1.95	13
Per weighted average unit - diluted (2)	$ **2.20**	$ 1.95	13
Declared distributions	$ **283,465**	$ 230,714	23
Per Unit (1)	**1.44**	1.44	-
Percent of cash flow distributed	**66%**	74%	(12)

(1) Excludes exchangeable shares

(2) Includes dilutive impact of unit options, exchangeable shares and convertible debentures.

For the year ended December 31, 2006, cash flow increased 39 percent or $121.5 million to $432.7 million from $311.2 million for 2005 (per unit in 2006 - $2.20; 2005 - $1.95). COGP generated $185.3 million, USOGP $63.0 million, and Midstream $184.4 million of cash flow during 2006. During 2005 COGP generated cash flow of $185.1 million, USOGP $59.8 million, and Midstream $66.3 million.

Canadian oil and gas operations cash flow contributed $185.3 million in 2006, virtually flat when compared with $185.1 million from 2005. The 2006 results reflect increased production from the Rainbow assets acquired on August 31, 2006, incremental production adds from the successful capital drilling programs in the core areas and higher realized crude oil and natural gas liquids prices, as well as realized gains on financial derivative instruments. These factors were offset by natural production declines, a lower realized natural gas price due to a decrease in the AECO natural gas index price, and higher general and administrative expenses when compared to 2005.

The Midstream business unit added $184.4 million to 2006 cash flow, 178 percent above the $66.3 million recorded in the year ended December 31, 2005. Midstream cash flow has benefited from the Midstream NGL Acquisition completed in December 2005. This acquisition has extended Provident's participation in the NGL value chain. Midstream cash flow reflects an increase in fees for services, fixed margin extraction and equity margin on marketed NGLs. Midstream cash flow from marketed NGLs benefited from an increase in propane plus prices in the year ended December 31, 2006 over 2005 accompanied by a reduction in associated product costs, mostly due to reduced natural gas prices.

The U.S. oil and gas operations provided increased cash flow of $63.0 million in 2006, compared to $59.8 million in 2005, resulting from a full year of production in 2006 from the Nautilus properties, acquired in March of 2005, and higher crude oil prices, partially offset by higher production expenses and general and administrative costs.

Declared distributions in 2006 totaled $283.5 million, 66 percent of cash flow. This compares to $230.7 million of declared distributions in 2005, 74 percent of cash flow. In previous years, Provident has paid out between 74 percent and 102 percent of its annual cash flow as distributions to unitholders. Provident's objective is to provide stable distributions to its unitholders.

Management uses cash flow from operations (before changes in non-cash working capital and site restoration expenditures) to analyze operating performance. Provident also reviews cash flow in setting monthly distributions and takes into account cash required for debt repayment and/or capital programs in establishing the amount to be distributed.

Cash flow as presented does not have any standardized meaning prescribed by Canadian generally accepted accounting principles (GAAP) and therefore it may not be comparable with the calculation of similar measures for other entities. Cash flow as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP. All references to cash flow

throughout this report are based on cash flow before changes in non-cash working capital and site restoration expenditures.

Distributions

The following table summarizes distributions paid as declared by the Trust since inception:

Record Date	Payment Date		Distribution Amount (Cdn$)	(US$)*
2006				
January 23, 2006	February 15, 2006	$	0.12	0.10
February 23, 2006	March 15, 2006		0.12	0.10
March 22, 2006	April 13, 2006		0.12	0.10
April 24, 2006	May 15, 2006		0.12	0.11
May 25, 2006	June 15, 2006		0.12	0.11
June 22, 2006	July 14, 2006		0.12	0.11
July 21, 2006	August 15, 2006		0.12	0.11
August 22, 2006	September 15, 2006		0.12	0.11
September 22, 2006	October 13, 2006		0.12	0.11
October 23, 2006	November 15, 2006		0.12	0.10
November 22, 2006	December 15, 2006		0.12	0.10
December 22, 2006	January 15, 2007		0.12	0.10
2006 Cash Distributions paid as declared		$	1.44	1.26
2005 Cash Distributions paid as declared			1.44	1.20
2004 Cash Distributions paid as declared			1.44	1.10
2003 Cash Distributions paid as declared			2.06	1.47
2002 Cash Distributions paid as declared			2.03	1.29
2001 Cash Distributions paid as declared – March 2001 – December 2001			2.54	1.64
Inception to December 31, 2006 – Distributions paid as declared		$	10.95	7.96

*exchange rate based on the Bank of Canada noon rate on the payment date.

For Canadian tax purposes, 2006 distributions were determined to be 93.2 percent taxable and 6.8 percent tax-deferred return of capital in the hands of Canadian unitholders. The 2005 comparables were 76.5 percent and 23.5 percent, respectively. Distributions received by U.S. resident unitholders in 2006 are classified as 97.7 percent qualified dividend and 2.3 percent tax deferred return of capital. The 2005 comparables were 94.4 percent and 5.6 percent respectively. In both Canada and the U.S., the tax-deferred portion would usually be treated as an adjustment to the cost base of the units. Unitholders or potential unitholders should consult their own legal or tax advisors as to their particular income tax consequences of holding Provident units.

Proposed taxation of trust distributions

The Canadian government made an unexpected announcement on October 31, 2006, stating its intention to introduce a substantial new 31.5 percent tax on income trust distributions beginning in 2011. This announcement caused a severe negative market reaction early in November. The government remains committed to this course of action in spite of compelling evidence of the very positive impact that energy trusts in particular have on the Canadian energy industry, on the economy in general, and on government tax revenues.

Since the original announcement, the government has also clarified the rules around the extent to which a trust is allowed to grow before 2011 without triggering immediate taxable status. A trust can double in size before 2011, and trusts can merge without penalty. This is positive, suggesting that Provident's near term business plan and growth objectives will not be affected by the taxation announcement.

Provident remains active in the efforts to try to convince the government to modify its proposal or to exempt energy trusts. As well as working with government, management is also actively engaged in strategic planning to determine the best course of action for Provident under the proposed new tax regime. With diverse businesses and a history of innovation, the Trust is well positioned to identify creative solutions. While it will take time to fully examine all options, management remains committed to making Provident a premier energy income and growth investment.

Net income

Consolidated	Year ended December 31,		
($ 000s, except per unit data)	**2006**	2005	% Change
Net income	**$ 140,920**	$ 96,926	45
Per weighted average unit			
– basic[1]	**0.72**	0.61	18
Per weighted average unit			
– diluted[2]	**0.72**	0.61	18

[1] Based on weighted average number of trust units outstanding

[2] Based on weighted average number of trust units outstanding including the dilutive impact of the unit option plan, exchangeable shares and convertible debentures.

	Year ended December 31,		
($ 000s)	**2006**	2005	% Change
COGP net income	**$ 83,453**	$ 35,352	136
USOGP net income	**2,598**	5,422	(52)
Total oil and gas net income	**86,051**	40,774	111
Midstream net income	**54,869**	56,152	(2)
Consolidated net income	**$ 140,920**	$ 96,926	45

Net income for the year ended December 31, 2006 increased to $140.9 million compared to $96.9 million of income in the comparable 2005 period.

The COGP business segment's net income was $83.4 million, a $48.0 million improvement over the year ended December 31, 2005 net income of $35.4 million. The increase was mainly due to a higher future income tax recovery and an increased unrealized gain on financial derivative instruments partially offset by increased depletion, depreciation, and accretion (DD&A) expense and a decrease in earnings before interest, taxes, depletion, depreciation, accretion and other non-cash items (EBITDA) driven by lower realized natural gas prices due to the decrease in the AECO natural gas index price, and lower production compared to 2005.

The Midstream unit recorded net income of $54.9 million as compared to $56.1 million in the year ended December 31, 2005. The increase reflects higher EBITDA in 2006. The Midstream business unit had EBITDA of $219.6 million in 2006 as compared to $70.7 million in 2005. This significant improvement in EBITDA is attributable to the Midstream NGL acquisition completed in December 2005. This acquisition has extended Provident's participation in the NGL value chain through increased managed volumes. Midstream EBITDA reflects an increase in fees for services, fixed margin extraction and equity margin on marketed NGLs. The significant improvement in Midstream EBITDA is also the result of an increase in propane plus prices in 2006 over 2005 accompanied by a reduction in associated product costs, mostly due to reduced natural gas prices. Partially offsetting this increase is unrealized losses on outstanding financial derivative instruments amounting to $68.3 million in 2006 (2005 - $1.6 million). Under generally accepted accounting principles, these unrealized "mark-to-market" amounts, which relate to financial instruments with effective periods ranging over the next five years from 2007 through 2011, are required to be recognized in the financial statements of Provident, affecting current period net income (see "Commodity price risk management program"). In addition, higher DD&A of $49.1 million compared to $11.8 million in 2005, and higher interest charges of $32.1 million versus $4.9 million in 2005 are the result of a larger asset base and increased capitalization due to the Midstream NGL Acquisition.

For the year ended December 31, 2006, USOGP net income was $2.6 million as compared to $5.4 million in the year ended December 31, 2005. USOGP generated a seven percent increase in EBITDA resulting from a full year of production in 2006 from the Nautilus properties, acquired in March of 2005 as well as higher crude oil prices. In addition, unrealized gains on financial derivative instruments were $7.7 million in 2006, compared to a loss of $1.9 million in 2005. These factors were offset by higher DD&A charges and increased non-cash unit based compensation in 2006.

Reconciliation of non-GAAP measure

The Trust calculates earnings before interest, taxes, depletion, depreciation, accretion and other non-cash items (EBITDA) within its segment disclosure. EBITDA is a non-GAAP measure. A reconciliation between EBITDA and income before taxes and non-controlling interests follows:

Consolidated EBITDA Reconciliation ($ 000s)		Year ended December 31, 2006		2005	% Change
EBITDA	$	**495,889**	$	349,181	42
Adjusted for:					
Interest and non-cash expenses excluding unrealized (loss) gain on financial derivative instruments		**(335,079)**		(229,372)	46
Unrealized (loss) gain on financial derivative instruments		**(43,314)**		7,684	-
Income before taxes and non-controlling interests	$	**117,496**	$	127,493	(8)

Reconciliation of cash flow distribution		Year ended December 31, 2006		2005	% Change
Cash provided by operating activities	$	**414,349**	$	257,363	61
Change in non-cash operating working capital		**13,693**		51,344	(73)
Site restoration expenditures		**4,622**		2,481	86
Cash flow from operations before changes in working capital and site restoration expenditures		**432,664**		311,188	39
Cash withheld for financing and investing activities		**(149,199)**		(80,474)	85
Cash distributions to unitholders		**283,465**		230,714	23
Accumulated cash distributions, beginning of period		**643,360**		412,646	56
Accumulated cash distributions, end of period	$	**926,825**	$	643,360	44
Cash distributions per unit	$	**1.44**	$	1.44	-

Cash withheld for financing and investing activities is a discretionary amount and represents the difference between cash flow from operations (before changes in working capital and site restoration expenditures) and distributions.

Taxes

Year ended December 31, ($ 000s)		2006		2005	% Change
Capital taxes	$	**1,314**	$	4,780	(73)
Current and withholding taxes		**5,829**		5,628	4
Future income tax (recovery) expense		**(34,316)**		17,793	-
	$	**(27,173)**	$	28,201	-

For the year ended December 31, 2006, the expected income tax expense was $40.7 million on income before taxes and non-controlling interests of $117.5 million. The difference from the expected expense and the total tax recovery of $27.2 million is primarily a result of deductions allowed when computing taxable income of the Trust for distributions made to unitholders. The Trust is a taxable entity under Canadian income tax law and is taxable only on income that is not distributed or distributable to the unitholders. If the Trust distributes all of its taxable income to the unitholders, no provision for taxes is required by the Trust. Since inception, the Trust has distributed all of its taxable income to the unitholders. Additionally, interest and royalties are charged by the Trust to its subsidiaries, which are deductible in the computation of taxable income at the incorporated subsidiary level reducing tax pool claims in certain subsidiaries and potentially creating tax loss carry-forwards that result in future income tax recoveries.

Capital taxes in the year ended December 31, 2006 totaled an expense of $1.3 million, a reduction from $4.8 million recorded in the year ended December 31, 2005. The reduction is due to the elimination of the federal large corporation tax effective January 1, 2006. This legislation was enacted on June 22, 2006.

The current and withholding taxes total $5.8 million in the year ended December 31, 2006, an increase of $0.2

million over the comparable 2005 period. These taxes arise from Provident's U.S. based operations, which are subject to U.S. federal and state income taxes. Also, payments from U.S. entities to Canadian entities are subject to withholding taxes if the distributions are characterized as dividends or interest.

In 2006, future income tax recovery totaled $34.3 million compared to an expense of $17.8 million in 2005. The recovery was generated by interest and royalty charges to incorporated subsidiaries from the Trust as well as tax rate reductions enacted in the second quarter of 2006.

Interest expense

Consolidated	Year ended December 31,		
($ 000s, except as noted)	**2006**	2005	% Change
Interest on bank debt	$ **34,666**	$ 10,875	219
Weighted-average interest rate on bank debt	**5.30%**	3.85%	38
Interest on 10.5% convertible debentures (2)	-	1,682	(100)
Interest on 8.75% convertible debentures	**2,573**	4,923	(48)
Interest on 8.0% convertible debentures	**2,500**	3,577	(30)
Interest on 6.5% convertible debentures (1)	**6,437**	5,393	19
Interest on 6.5% convertible debentures (3)	**9,715**	1,219	697
Total cash interest	$ **55,891**	$ 27,669	102
Weighted average interest rate on all long-term debt	**5.81%**	4.91%	18
Non-cash accretion expense - convertible debentures	**2,694**	2,849	(5)
Total interest including accretion on convertible debentures	$ **58,585**	$ 30,518	92

(1) On March 1, 2005 the Trust issued $100.0 million of unsecured subordinated convertible debentures with a 6.5 percent coupon rate maturing August 31, 2012.

(2) On May 31, 2005 the Trust redeemed the 10.5 percent unsecured subordinated convertible debentures issuing 3.5 million trust units and $3.0 million in cash.

(3) On November 15, 2005 the Trust issued $150.0 million of unsecured subordinated convertible debentures with a 6.5 percent coupon rate maturing April 30, 2011.

Interest on bank debt increased in 2006 compared to 2005 due to increased capitalization including debt levels that resulted from the $773 million Midstream NGL Acquisition in the fourth quarter of 2005 and the $473 million Rainbow asset acquisition in the third quarter of 2006. As well, increases in the Canadian prime rate and the U.S. LIBOR rate have resulted in higher interest rates on bank debt.

Cash interest expense on debentures increased in 2006 compared to 2005 reflecting the March 1, 2005 issue of $100 million of 6.5 percent subordinated convertible debentures and the November 15, 2005 issue of $150 million of 6.5 percent subordinated convertible debentures, partly offset by redemptions and conversions of subordinated convertible debentures.

Financial instruments

Commodity price risk management program

For the year ended December 31, 2006 $13.5 million was recorded as a realized loss on financial derivative instruments due to the Commodity Price Risk Management Program (the Program) with $1.9 million related to the combined oil and gas operations as a realized gain and a realized loss of $15.4 million associated with the Midstream segment.

In the oil and gas business units the realized loss in 2006 associated with crude oil totaled $5.7 million ($0.97 per barrel) and a realized gain of $7.6 million related to natural gas ($0.25 per gj). The combined total was a gain of $1.9 million or $0.16 per boe. In 2005 the Program recorded a realized loss of $64.6 million or $5.24 per boe with $59.0 million related to crude oil ($8.36 per barrel) and $5.6 million related to natural gas ($0.19 per gj).

In 2006 the Midstream segment recorded a realized loss of $15.4 million primarily on propane and ethane price stabilization and frac-spread margin hedging activities. In 2005 the Program recorded a realized loss of $2.3 million for these activities.

Realized gains on foreign exchange contracts which fixed the exchange rates on foreign currency contracts related to the Program have been presented as a component of foreign exchange gain and other and allocated to their respective business segments.

On a per trust unit basis the opportunity cost of the Program decreased to $0.07 per trust unit in 2006 from $0.42 per trust unit in 2005.

At December 31, 2006 the mark to market value of open contracts was in a net loss position of $52.9 million based upon commodity prices prevailing at that date. Under generally accepted accounting principles, these unrealized "mark-to-market" opportunity costs, which relate to hedging positions with effective periods ranging over the next five years from 2007 through 2011, are required to be recognized in the financial statements of Provident, affecting current period net income. These unrealized opportunity costs relate to financial derivative instruments which were entered into in order to manage commodity prices and protect future Midstream product margins. Fluctuations in the market value of these instruments have no impact on cash flow until the instruments are settled.

Provident's commodity price risk management program includes a consistent, active and disciplined hedging program that utilizes derivative instruments to provide for insurance against lower commodity prices and price volatility. The program provides support for stable cash distributions, capital programs and bank financing. The hedging strategy protects a percentage of Provident's oil and natural gas production against a decline in commodity prices while, with some products, allowing the Trust to participate in a rising commodity price environment. It provides price stabilization and protection of a percentage of inventory values and fractionation spread margin associated with the midstream services and marketing business unit. As well, the Provident hedging strategy reduces foreign exchange risk due to the exposure arising from the conversion of U.S. dollars into Canadian dollars.

Provident will continue to execute the program in 2007. The derivative instruments the Trust uses include puts, calls, costless collars, participating swaps, fixed and indexed referenced pricing.

Disclosure Controls and Procedures: U.S. Sarbanes-Oxley Act

In 2002, the United States Congress enacted the Sarbanes-Oxley Act (SOX), which stipulated that corporations publicly traded on U.S. financial exchanges must have assessed the effectiveness of their internal controls over financial reporting by December 31, 2006. As a foreign filer listed on the New York Stock Exchange, Provident was required to conduct the assessment.

Based on their evaluation as of December 31, 2006, Provident's chief executive officer and chief financial officer concluded that Provident's disclosure controls and procedures (as defined in Rules 13(a)-15(e) and 15(d)-15(e) under the United States Securities Exchange Act of 1934 (the Exchange Act) are effective to ensure that information required to be disclosed by Provident in reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the United States Securities and Exchange Commission rules and forms. In addition, other than as described below, as of December 31, 2006, there were no changes in Provident's internal controls over financial reporting that occurred during 2006 that have materially affected, or are reasonably likely to materially affect its internal controls over financial reporting.

Provident will continue to periodically evaluate its disclosure controls and procedures and internal controls over financial reporting and will make any modifications from time to time as deemed necessary.

The Trust has undertaken a comprehensive review of the effectiveness of its internal control over financial reporting as part of the reporting, certification and attestation requirements of Section 404 of the U.S. Sarbanes-Oxley Act of 2002. For the year ended December 31, 2006, the company's internal controls were found to be operating free of any material weaknesses.

Property Acquisitions

On August 31, 2006 Provident acquired a package of natural gas producing assets in the Rainbow and Peace River Arch areas of northwestern Alberta. The assets provide daily production of approximately 5,500 barrels of oil equivalent, over 90 percent of which is natural gas, and over 200 identified drilling locations.

The purchase price was $472.8 million (including acquisition costs) and was financed by the issuance of 16,325,000 units at $13.85 per unit and Provident's credit facilities (see note 3 to consolidated financial statements).

In the fourth quarter of 2006, Provident spent $8.6 million on oil and gas property acquisitions primarily on acquiring additional working interests in Northwest Alberta ($6.7 million) and in Southern Alberta ($1.7 million).

Goodwill

Goodwill represents the excess of the cost of an acquired enterprise over the net of the amounts assigned to assets acquired and liabilities assumed. In 2005, the Midstream NGL Acquisition resulted in additional goodwill of $100.4 million (as adjusted in 2006. See note 3 to the consolidated financial statements). Goodwill of $330.9 million arose from COGP acquisitions in 2002 and 2004.

Goodwill is assessed for impairment at least annually, and if an impairment exists, it would be charged to income in the period in which the impairment occurs. Provident engaged an independent accounting firm to assist in performing an impairment test at year end. The impairment test includes, amongst other variables, a comparison of the net book value of the Trust's assets to the market value of the Trust's equity. Goodwill is not amortized.

Liquidity and capital resources

Consolidated	December 31,		
($ 000s)	**2006**	2005	% Change
Long-term debt - revolving term credit facilities	$ **702,993**	$ 586,597	20
Long-term debt - convertible debentures	**285,792**	298,007	(4)
Total debt	**988,785**	884,604	12
Equity (at book value)	**1,542,974**	1,404,826	10
Total capitalization at book value	$ **2,531,759**	$ 2,289,430	11
Total debt as a percentage of total book value capitalization	**39%**	39%	-

Provident operates three business units with similar but not identical monthly cash settlement cycles. Provident's working capital position is impacted by seasonal fluctuations that reflect commodity price changes, drilling cycles in its oil and gas operations and inventory balances in its midstream business unit. Provident relies on cash flow from operations, external lines of credit and access to equity markets to fund capital programs and acquisitions.

Long-term debt and working capital

As at December 31, 2006 Provident had drawn on 63 percent of its term credit facilities of $925 million and U.S. $158 million as compared to 68 percent drawn on its $750 million and U.S. $100 million term credit facilities as at December 31, 2005. The increase in the level of bank debt was due to the increased scale of operations primarily due to acquisitions.

At December 31, 2006 Provident had letters of credit guaranteeing Provident's performance under certain commercial and other contracts that totaled $31.9 million, increasing bank line utilization to 66 percent. The guarantees at December 31, 2005 totaled $45.1 million.

Provident's working capital decreased by $23.6 million from $79.4 million to $55.8 million as at December 31, 2006. Of the decrease, $24.8 million is due to a reduction in inventory and $21.8 million due to a reduction in cash and cash equivalents. These decreases in working capital are partially offset by a $14.7 million reduction in accounts payable and accrued liabilities and a $4.4 million reduction in net current financial derivative instrument liability.

The ratio of debt to cash flow in 2006 was 2.3 to one, compared to 2.8 to one in 2005. Fourth quarter cash flow in 2006 was $122.7 million. The ratio of debt to annualized fourth quarter cash flow was 2.0 to one, as compared to 2005 fourth quarter annualized debt to cash flow of 2.3 to one. The reduction in debt to cash flow figures is due to increased cash flows as a result of the Midstream NGL Acquisition.

Trust units and exchangeable shares

On July 31, 2006 the Trust issued 16,325,000 Subscription Receipts at a price of $13.85 per Subscription Receipt for total proceeds of $226.1 million ($214.2 million net of issue costs). Each Subscription Receipt entitled the holder to receive one trust unit upon completion of the Rainbow asset acquisition. The acquisition closed on August 31, 2006 at which time all the outstanding Subscription Receipts were converted into trust units. At that time, the holders of the Subscription Receipts were also entitled to $0.12 per trust unit, which is the equivalent of the August distribution paid in September. This payment was treated as a reduction to the proceeds received for the units issued through the Subscription Receipts to $13.73 per trust unit, reducing the amount attributed to Unitholders' contributions by $2.0 million. Proceeds from the issue were used to fund the Rainbow asset acquisition.

In 2006, 0.9 million units were issued on conversion of exchangeable shares with a value of $9.0 million (2005 – 3.0 million units; conversion amount $28.4 million). For the year ended December 31, 2006 the Trust issued 1.3 million units on conversion of convertible debentures (2005 – 9.6 million units). An additional 0.9 million units pursuant to the unit option plan were issued for the year ended December 31, 2006 (2005 – 2.3 million units). Under Provident's Premium Distribution, Distribution Reinvestment (DRIP) and Optional Unit Purchase Plan program 3.0 million units were elected in 2006 and were issued or are to be issued representing proceeds of $36.9 million (2005 – 1.4 million units for proceeds of $18.4 million).

At December 31, 2006 management and directors held approximately 1.0 percent of the outstanding units and exchangeable shares.

Non-Controlling Interest

(i) USOGP operations

Non-controlling interest USOGP ($ 000s)	Year ended December 31, 2006	2005
Non-controlling interest, beginning of year	$ **11,885**	$ 13,649
Net income attributable to non-controlling interest	**2,995**	1,596
Distributions to non-controlling interest holders	**(6,523)**	(3,360)
Investments by non-controlling interest	**72,754**	-
Non-controlling interest, end of year	**81,111**	11,885
Accumulated income attributable to non-controlling intereest	$ **5,514**	$ 2,519

A non-controlling interest arose from Provident's June 15, 2004 acquisition of 92 percent of BreitBurn Energy Company L.P. (BreitBurn) of Los Angeles, California. Additional investments since June 2004 by Provident in BreitBurn have reduced the non-controlling interest percentage at December 31, 2006 to approximately 4.4 percent (2005 – 4.4 percent). Contributions by this non-controlling interest total $0.5 million in 2006 (2005 – nil).

In the second quarter of 2006, a USOGP subsidiary began a land development project with a partner. The subsidiary has a 20 percent interest, with the partner holding 80 percent. Because the subsidiary stands to receive a majority share of the future proceeds, Provident is consolidating the results in its statements, with non-controlling interest. Contributions by the non-controlling interest total $3.7 million in 2006.

In the fourth quarter of 2006, Provident's subsidiary, BreitBurn Energy Partners, L.P. (the "MLP") completed its initial public offering. BreitBurn transferred oil and gas properties comprising approximately half of its proved reserves and two thirds of its daily production to the MLP. The offering, including an underwriter's option, of 6,900,000 common units at U.S. $18.50 per unit, resulted in approximately 34 percent of the MLP held by partners not controlled by Provident. Contributions by this non-controlling interest total $131.6 million in 2006. Non-controlling interest was increased by $68.5 million as a result of this transaction. The difference of $63.1 million has been recorded against property, plant and equipment in accordance with full cost accounting principles.

(ii) Exchangeable shares

Following is a summary of the non-controlling interest – exchangeable shares for the years ended December 31, 2006 and 2005:

Non-controlling interest - Exchangeable shares ($ 000s)		2006		2005
Non-controlling interest, beginning of year	$	**8,259**	$	35,921
Reduction of book value for conversion to trust units		**(9,013)**		(28,432)
Net income attributable to non-controlling interest		**754**		770
Non-controlling interest, end of year	$	**-**	$	8,259
Accumulated income attributable to non-controlling interest	$	**-**	$	2,252

In 2006, all outstanding exchangeable shares were converted into Provident trust units.

Capital expenditures and funding

Consolidated	Year ended December 31,		
($ 000s)	**2006**	2005	% Change
Capital Expenditures and Funding			
Capital Expenditures			
Capital expenditures and reclamation fund contributions	$ **(193,183)**	$ (159,398)	21
Property acquisitions	**(480,357)**	(586)	81,872
Corporate acquisitions	**(1,036)**	(863,723)	(100)
Property dispositions	**(1,268)**	45,100	-
Net capital expenditures	$ **(675,844)**	$ (978,607)	(31)
Funded By			
Cash flow net of declared distributions to unitholders and non-controlling interest	$ **142,676**	$ 77,114	85
Increase in long-term debt	**117,385**	325,771	(64)
Issue of convertible debentures, net of issue costs	-	239,822	(100)
Redemption of convertible debentures	-	(2,997)	(100)
Issue of trust units, net of issue costs; excluding DRIP	**220,225**	377,362	(42)
DRIP proceeds	**36,851**	18,443	100
Contributions by non-controlling interests	**135,829**	-	-
Change in working capital, including cash, payment of financial derivative instruments and sale of assets	**22,878**	(56,908)	-
Net capital expenditure funding	$ **675,844**	$ 978,607	(31)

Capital expenditures were funded by a combination of cash flow, debt and equity issued from treasury through public offerings, the DRIP program and contributions by non-controlling interest. Provident's strategy is to fund acquisitions by accessing the capital markets and to fund capital expenditures through cash flow, DRIP and other equity if needed.

Net asset value

Provident's net asset value ("NAV") as at December 31, 2006, is summarized in the table below. The net asset value is calculated on a diluted basis, which includes exchangeable shares and unit options, and is presented at eight percent and 10 percent discounted cash flow cases. The pricing used at both December 31, 2006 and December 31, 2005 is derived from a report prepared by McDaniel & Associates Consultants Ltd., independent engineers.

($ 000s except per unit data)	PV 8%	PV 10%
Net Asset Value:		
Present value of proved plus probable oil and natural gas reserves (1) (2)	**$ 1,933,338**	$ 1,726,538
Midstream assets (3)	**1,737,905**	1,493,039
Add:		
Working Capital	**65,500**	65,500
Land (4) (5)	**48,923**	48,923
Proceeds from Options	**20,283**	20,283
Cash Reserved for Future Reclamation	**-**	-
Investments	**4,320**	4,320
Less:		
Financial Hedging Losses (2)	**27,769**	26,290
Long Term Debt	**(988,785)**	(988,785)
Other long-term liabilities	**(16,305)**	(16,305)
Non-controlling interest - USOGP operations	**(81,111)**	(81,111)
Consolidated Provident Net Asset Value	**$ 2,751,837**	**$ 2,298,692**
Consolidated Provident Net Asset Value per Unit	**$ 12.90**	**$ 10.77**
2005 comparatives		
Consolidated Provident Net Asset Value per Unit	$ 13.04	$ 11.15

(1) Evaluated by McDaniel and NSA.

(2) Pricing is based on McDaniel pricing effective December 31, 2006.

(3) The Midstream assets represent discounted estimated cash flow streams (EBITDA less maintenance capital) for 25 years.

(4) Canadian land holdings evaluated by Seaton Jordan & Associates Ltd. effective December 31, 2006.

Non-cash unit based compensation

Non-cash unit based compensation include expenses or recoveries associated with Provident's unit option plan, restricted and performance unit plan, unit appreciation rights and other unit based compensation plans. Provident accounts for the unit option plan using the fair value of the option, at the time of issue. The other unit based compensation is recorded at the estimated fair value of the notional units granted. Compensation expense associated with the plans is deferred and recognized in earnings over the vesting periods of each plan. Provident recorded a non-cash expense of $23.1 million for the year ended December 31, 2006 (2005 – $9.8 million) included in general and administrative expense. At December 31, 2006, the current portion of the liability totaled $18.2 million and the long-term portion totaled $16.3 million.

Outlook

With a $170 million capital budget, Provident is expecting another active year in 2007. Weakening commodity prices early in the year impacted cash flow, although management is taking advantage of the stronger forward commodity prices to add some additional hedging to protect a floor level of EBITDA in each of the business units.

In the Canadian Oil and Gas Production business (COGP), Provident intends to spend $72 million across its six operating areas in 2007. Over half of that capital will be deployed on the recently-acquired assets in Northwest Alberta and the organic shallow gas play in Southwest Saskatchewan. The planned divestiture of heavy oil assets in Lloydminster that was mentioned in the third quarter press release did not take place. Provident did not receive bids of sufficient value to warrant a transaction, reflecting the uncertainty in the marketplace late in the year caused by the government taxation announcement.

Provident expects COGP production to average 22,000 to 24,000 boed in 2007. Operating costs should stay reasonably consistent with 2006 levels. In 2007, COGP will continue to focus on strengthening internal operating capability, and specifically on applying the shallow gas knowledge gained in Southwest Saskatchewan to the new natural gas assets in Northwest Alberta.

In the U.S. Oil and Gas Production business (USOGP), Provident plans to spend $53 million in 2007, a significant portion of which will be used for Orcutt and other growth opportunities. The MLP will continue to pursue acquisition opportunities that fit its successful business model, such as the Permian Basin acquisition that was completed early in 2007. Production is expected to average 8,000 to 8,500 boed in 2007, which includes both the

MLP and the pre-existing business. These numbers assume initial production from the Orcutt diatomite project late in 2007. Operating costs are expected to stay fairly consistent with 2006 levels, as weaker commodity prices have not yet translated into lower costs in that business.

In the Midstream business, Provident plans to spend $42 million in capital expenditures in 2007, of which only $6 million is required for sustaining capital. The remainder is planned for growth projects including further expansion of the condensate rail offloading terminal and new storage caverns at Redwater.

2007 Midstream EBITDA will depend on the business environment. Thus far in the first quarter, frac spreads have weakened from their 2006 highs, and lower commodity prices have reduced product margins in absolute terms. However, propane demand has been strong in Eastern North America, effectively drawing down Provident's substantial winter propane inventories.

The remaining $3 million in capital is intended for corporate purposes. In addition, the Trust will incur one-time net expenditures of approximately $23 million in 2007 and 2008 related to a move of the Calgary head office into a new building. These expenditures will be amortized over the 14 year term of the lease. As a result of Provident's growth, employees are currently housed in two buildings, both of which are full to capacity. The planned 2008 move into Livingston Place, an office complex currently under construction, will accommodate growth and improve efficiency by consolidating all employees into a single location.

With respect to corporate priorities for 2007, Provident management will continue to develop strategy in response to the government taxation announcement in 2007, as well as evaluate acquisition opportunities that may arise as the energy trust sector adjusts to the planned tax changes. As always, Provident's primary focus is on delivering long-term value and sustainability for unitholders. In 2006, the Trust delivered a total return for investors of 13.8 percent, which was among the very best of the energy trusts in a challenging year.

COGP segment review

Crude oil and liquids price

COGP	Year ended December 31,		
($ per bbl)	**2006**	2005	% Change
Oil per barrel			
WTI (US$)	**$ 66.22**	$ 56.56	17
Exchange rate (from US$ to Cdn$)	**1.13**	1.21	(7)
WTI expressed in Cdn$	**$ 74.83**	$ 68.44	9
Realized pricing before financial derivative instruments			
Light/Medium oil	**$ 57.18**	$ 52.02	10
Heavy oil	**$ 36.80**	$ 31.33	17
Natural gas liquids	**$ 51.91**	$ 49.15	6
Crude oil and natural gas liquids	**$ 52.38**	$ 45.25	16

The above prices are net of transportation expense.

For the year ended December 31, 2006 COGP's realized crude oil and natural gas liquids price, prior to the impact of financial derivative instruments, increased by 16 percent to average $52.38 compared to $45.25 in 2005. The 2006 increase related to a 17 percent higher US$ WTI crude oil price, narrower pricing differentials on all crude oil streams and a reduction in Provident's heavy oil volumes as a percentage of its oil production mix price partially offset by a stronger Canadian dollar.

Natural gas price

COGP	Year ended December 31,		
($ per mcf)	**2006**	2005	% Change
AECO monthly index (Cdn$ per mcf)	**$ 6.98**	$ 8.49	(18)
Corporate natural gas price per mcf before financial derivative instruments	**$ 6.66**	$ 8.42	(21)

The above prices are net of transportation expense.

For the year ended December 31, 2006 COGP's realized natural gas price, excluding financial derivative instruments, decreased 21 percent as compared to 2005, comparable to the decrease in the benchmark AECO monthly index price. Provident markets approximately 17 percent of its natural gas to aggregators and mainly sells to the market on daily indices, receiving prices that are based on the heat content of the natural gas. Provident's realized prices and changes in prices can therefore differ from benchmark indices.

Production

COGP	Year ended December 31,		
	2006	2005	% Change
Daily production			
Crude oil - Light/Medium (bpd)	**6,815**	8,058	(15)
- Heavy (bpd)	**2,057**	4,358	(53)
Natural gas liquids (bpd)	**1,401**	1,572	(11)
Natural gas (mcfd)	**82,469**	74,936	10
Oil equivalent (boed) [1]	**24,018**	26,477	(9)

[1] Provident reports equivalent production converting natural gas to oil on a 6:1 basis.

For the year ended December 31, 2006, COGP production averaged 24,018 boed, a nine percent decrease compared to 26,477 boed in 2005. The additional production from the Rainbow assets acquired on August 31, 2006 and the production volumes added through drilling and optimization activities were more than offset by the disposition of 2,100 boed of production in September 2005 and natural production declines.

Provident does not have any single property providing greater than 10 percent of total production, which mitigates exposure to production failure.

COGP's production summarized by core areas is as follows:

COGP Year ended December 31, 2006	West Central Alberta	Southern Alberta	Northwest Alberta	Southeast Saskatchewan	Southwest Saskatchewan	Lloydminster	Other	Total
Daily production								
Crude oil - Light/Medium (bpd)	1,109	2,244	58	1,704	321	1,322	57	6,815
- Heavy (bpd)	-	-	-	-	-	2,057	-	2,057
Natural gas liquids (bpd)	1,227	127	24	-	-	22	1	1,401
Natural gas (mcfd)	34,989	23,195	8,778	164	13,820	1,324	199	82,469
Oil equivalent (boed) [1]	8,168	6,237	1,545	1,731	2,624	3,622	91	24,018

COGP Year ended December 31, 2005	West Central Alberta	Southern Alberta	Northwest Alberta	Southeast Saskatchewan	Southwest Saskatchewan	Lloydminster	Other	Total
Daily production								
Crude oil - Light/Medium (bpd)	1,300	2,722	-	1,714	845	1,470	7	8,058
- Heavy (bpd)	-	-	-	-	-	4,358	-	4,358
Natural gas liquids (bpd)	1,406	149	-	-	1	16	-	1,572
Natural gas (mcfd)	40,198	26,345	-	202	6,260	1,909	22	74,936
Oil equivalent (boed) [1]	9,406	7,262	-	1,747	1,889	6,162	11	26,477

[1] Provident reports equivalent production converting natural gas to oil on a 6:1 basis.

Internal development activities included 59.0 net wells drilled for the year ended December 31, 2006 with a 98 percent success rate. Provident's most active areas, southeast and southwest Saskatchewan realized 31.5 net wells drilled. The focus of southern Saskatchewan is a shallow gas drilling program that will realize production and reserve additions for several years. Provident's other core areas remain active with additional activity in southern Alberta where Provident is actively drilling shallow gas wells resulting in 14.3 net wells drilled and in Lloydminster where Provident is drilling low risk heavy oil wells. In West Central Alberta, Provident continues its strategy of

farming out high risk exploration land to generate cash flow with minimal or no capital outlay. COGP's new area, Northwest Alberta, drilled 5.4 net wells in 2006 as it began the winter drilling program, which was ahead of its planned 2007 drilling schedule due to favourable weather conditions and advanced planning. Additions to proved plus probable reserves before revisions through internal capital replaced approximately 42 percent of annual production.

Revenue and royalties

COGP	Year ended December 31,		
($ 000s except per boe and mcf data)	**2006**	2005	% Change
Oil			
Revenue	**$ 169,852**	$ 202,845	(16)
Realized loss on financial derivative instruments	**(3,193)**	(42,700)	(93)
Royalties (net of ARTC)	**(32,567)**	(40,067)	(19)
Net revenue	**$ 134,092**	$ 120,078	12
Net revenue (per barrel)	**$ 41.41**	$ 26.50	56
Royalties as a percentage of revenue	**19.2%**	19.8%	
Natural gas			
Revenue	**$ 200,584**	$ 230,195	(13)
Realized gain (loss) on financial derivative instruments	**7,564**	(5,608)	-
Royalties (net of ARTC)	**(42,200)**	(48,484)	(13)
Net revenue	**$ 165,948**	$ 176,103	(6)
Net revenue (per mcf)	**$ 5.51**	$ 6.44	(14)
Royalties as a percentage of revenue	**21.0%**	21.1%	
Natural gas liquids			
Revenue	**$ 26,545**	$ 28,203	(6)
Royalties	**(6,458)**	(6,852)	(6)
Net revenue	**$ 20,087**	$ 21,351	(6)
Net revenue (per barrel)	**$ 39.28**	$ 37.21	6
Royalties as a percentage of revenue	**24.3%**	24.3%	
Total			
Revenue	**$ 396,981**	$ 461,243	(14)
Realized gain (loss) on financial derivative instruments	**4,371**	(48,308)	-
Royalties (net of ARTC)	**(81,225)**	(95,403)	(15)
Net revenue	**$ 320,127**	$ 317,532	1
Net revenue (per boe)	**$ 36.52**	$ 32.86	11
Royalties as a percentage of revenue	**20.5%**	20.7%	

Note: the above revenue, net revenue and net revenue per boe figures are presented net of transportation expenses.

For the year ended December 31, 2006 COGP production revenue was $397.0 million, a decrease of 14 percent from $461.2 million in 2005. The decrease in revenue is a result of lower realized natural gas price and lower crude oil and natural gas liquids production partially offset by higher realized crude oil and natural gas liquids prices and the additional natural gas production from the Rainbow assets acquired on August 31, 2006. Royalties as a percentage of revenue have remained relatively constant at approximately 20.5 percent compared to the prior year. The preceding factors, as well as the $4.4 million realized gain on financial derivative instruments compared to a $48.3 million loss in 2005, account for net revenue of $320.1 million in 2006, one percent higher than the $317.5 million recorded in 2005.

Net revenue per boe in 2006 increased 11 percent to $36.52 from $32.86 in 2005 resulting primarily from a higher realized gain on financial derivative instruments and a reduction of lower priced heavy oil volumes to nine percent of total production in 2006 compared to 16 percent in 2005 and increases in realized crude oil and natural gas liquids prices. These price increases were more than offset by lower realized natural gas prices as described above combined with the increased proportion of natural gas production to 57 percent of total production in 2006 compared to 47 percent in 2005.

Production expenses

COGP ($ 000s, except per boe data)		Year ended December 31, 2006		2005	% Change
Production expenses	$	**97,626**	$	95,278	2
Production expenses (per boe)	$	**11.14**	$	9.86	13

For the year ended December 31, 2006 production expenses increased two percent to $97.6 million from $95.3 million and increased by 13 percent to $11.14 per boe from $9.86 per boe in the prior year. Throughout 2006, operating expenses continued to increase in a number of categories including well servicing, maintenance, fluid hauling, and power and fuel and combined with lower production volumes resulted in higher operating costs on a per boe basis. Cost increases included higher than expected costs for electricity and adjustments related to prior periods operating costs by operators on non-operated properties. Cost increases in power and fuel, chemicals and well servicing reflect higher commodity prices and labour costs.

Operating netback

COGP ($ per boe)		Year ended December 31, 2006		2005	% Change
Netback per boe					
Gross production revenue	$	**45.29**	$	47.73	(5)
Royalties (net of ARTC)		**(9.27)**		(9.87)	(6)
Operating costs		**(11.14)**		(9.86)	13
Field operating netback		**24.88**		28.00	(11)
Realized gain (loss) on financial derivative instruments		**0.50**		(5.00)	-
Operating netback after realized financial derivative instruments	$	**25.38**	$	23.00	10

COGP operating netbacks have transportation expense netted against gross production revenue.

The 2006 field operating netback of $24.88 per boe was 11 percent below the $28.00 per boe for the prior year. This reflects COGP's lower realized natural gas prices due to the decrease in benchmark AECO monthly index price combined with the increased proportion of natural gas production to 57 percent of total production from 47 percent in 2005. This was partially offset by increased realized crude oil and natural gas liquids prices and a decrease in COGP's production mix of low netback heavy oil to nine percent in 2006 from 16 percent in 2005. Royalties, which are price sensitive, decreased by six percent on a boe basis reflecting lower prices, prior to the impact of financial derivative instruments. The 2006 operating netbacks after financial derivative instruments increased by 10 percent to $25.38 from $23.00 in the prior year due to the preceding factors as well as a realized gain on financial derivative instruments of $0.50 per boe compared to losses of $5.00 per boe in the prior year.

General and administrative

COGP ($ 000s, except per boe data)		Year ended December 31, 2006		2005	% Change
Cash general and administrative	$	**24,065**	$	18,552	30
Non-cash unit based compensation		**4,320**		2,640	64
	$	**28,385**	$	21,192	34
Cash general and administrative (per boe)	$	**2.75**	$	1.92	43

In 2006 COGP cash general and administrative expenses increased 30 percent to $24.1 million compared to $18.6 million in 2005. On a boe basis, cash general and administrative expenses increased 43 percent to $2.75 per boe in

2006 compared to the $1.92 per boe in the prior year. The increase in cash general and administrative expenses reflects additional costs associated with a more competitive landscape affecting the cost of hiring and compensating employees and consultants as well as increases in rent, insurance and compliance and reporting costs, including costs related to the implementation of procedures and documentation in connection with the U.S. Sarbanes-Oxley Act.

COGP operations are capable of absorbing additional production, particularly in existing core areas, with little impact on cash general and administrative expenses.

Non-cash unit based compensation increased 64 percent to $4.3 million in 2006 from $2.6 million in 2005. The increase reflects a more competitive landscape affecting the cost of hiring and compensating employees and increased incentives due to performance of the Trust on specific performance indicators.

Capital expenditures

COGP	Year ended December 31,			
($ 000s)		**2006**		2005
Capital expenditures - by area				
West central Alberta	**$**	**11,280**	$	10,514
Southern Alberta		**17,619**		21,513
Northwest Alberta		**4,883**		-
Southeast Saskatchewan		**1,941**		3,147
Southwest Saskatchewan		**25,677**		38,496
Lloydminster		**7,262**		9,865
Office and other		**1,426**		1,867
Total additions	**$**	**70,088**	$	85,402
Capital expenditures - by category				
Geological, geophysical and land	**$**	**4,508**	$	8,473
Drilling, recompletions, and workovers		**56,807**		41,315
Facilities and equipment		**6,353**		33,626
Other capital		**2,420**		1,988
Total additions	**$**	**70,088**	$	85,402
Property acquisitions	**$**	**482,369**	$	586
Property dispositions	**$**	**(1,264)**	$	45,100

In 2006, Provident's COGP segment spent $27.6 million in the Southeast and Southwest Saskatchewan core areas on acquiring mineral rights for future development ($3.2 million), drilling for shallow gas and recompletions ($21.5 million), and facility work ($2.9 million). In Southern Alberta $17.6 million was spent on drilling activities and recompletions ($15.5 million), facility upgrades ($0.9 million) and seismic and mineral rights acquisitions ($1.1 million). In West central Alberta $11.3 million was spent largely on non-operated drilling ($8.5 million) and facility work ($2.2 million). COGP's new area, Northwest Alberta, spent $4.9 million primarily on drilling activities and preparation for the winter drilling program which was ahead of its planned winter drilling schedule at year end. Provident spent $7.3 million in the Lloydminster area primarily on drilling and recompletion activities ($6.9 million) and facility work ($0.3 million). Office and other items accounted for $1.4 million of capital.

On August 31, 2006 Provident acquired a package of natural gas producing assets in the Rainbow and Peace River Arch areas of northwestern Alberta. The assets are expected to provide daily production of approximately 5,500 barrels of oil equivalent, over 90 percent of which is natural gas, and over 200 identified drilling locations.

The purchase price was $472.8 million (including acquisition costs) and was financed by the issuance of 16,325,000 units at $13.85 per unit and Provident's credit facilities (see note 3 to consolidated financial statements).

In the fourth quarter of 2006, COGP also spent $8.6 million on property acquisitions primarily on acquiring additional working interests in Northwest Alberta ($6.7 million) and in Southern Alberta ($1.7 million).

In 2005 asset dispositions of non-core assets totaled $45.1 million, primarily consisting of the September 29, 2005 non-core properties disposition of $44.6 million. COGP will continue to seek opportunities to dispose of its non-core properties given the competitive property market.

Depletion, depreciation and accretion (DD&A)

COGP	Year ended December 31,		
($ 000s, except per boe data)	**2006**	2005	% Change
DD&A	$ **168,953**	$ 155,929	8
DD&A per boe	$ **19.27**	$ 16.13	19

The COGP DD&A rate of $19.27 per boe increased 19 percent for 2006 compared to $16.13 per boe in 2005. The increase was primarily as a result of the Rainbow asset acquisition. Additions to property, plant and equipment of $660.4 million for the acquisition include $185.7 million due to the recording of future income taxes. This, combined with higher net per boe reserve acquisition costs, resulted in increased per boe DD&A. The cost of acquiring or drilling proved reserves in western Canada in an environment with higher commodity prices and increased drilling costs will be reflected in the DD&A rate going forward.

In 2006 DD&A also includes accretion expense associated with asset retirement obligation of $1.9 million (2005 - $2.5 million).

As part of the reconciliation of Provident's financial statements to United States generally accepted accounting principles (U.S. GAAP), disclosed in note 18 to consolidated financial statements, the Trust has reflected additional depletion in 2006 of $382.2 million (2005 – nil) and a related future income tax recovery of $114.7 million as a result of the application of the U.S. GAAP ceiling test. These changes were not required under Canadian generally accepted principles.

USOGP segment review

The USOGP business unit incorporates activities from certain Provident subsidiaries comprising an oil and gas exploitation and production organization based in Los Angeles, California.

In the fourth quarter of 2006, Provident, through its USOGP subsidiaries, completed its initial public offering ("IPO") of 6.9 million units at U.S. $18.50 per unit of BreitBurn Energy Partners, L.P. (the "MLP"). This master limited partnership (NASDAQ-BBEP) is a U.S. public, tax flow-through entity similar to Canadian royalty and income trusts such as Provident. Selected producing assets in the Los Angeles basin in California and in Wyoming were transferred to the MLP. The MLP operates approximately two-thirds of existing USOGP production and approximately one-half of USOGP reserves. The previously existing subsidiary ("BreitBurn") continues to operate some Los Angeles basin assets at West Pico and the Orcutt field (which is the site of the steam-assisted diatomite pilot project). At December 31, 2006 the Trust indirectly owns approximately 66 percent of the MLP and 96 percent of BreitBurn. The MLP and BreitBurn continue to be managed by the management team which operated the USOGP business unit prior to the IPO. The USOGP segment includes the consolidated results of the MLP and BreitBurn. Non-controlling interests include the public ownership in the MLP, the ownership interests of the managers in the MLP and BreitBurn, as well as third party investment in USOGP's land development project which commenced in the second quarter of 2006.

Crude oil, natural gas liquids and natural gas pricing

USOGP	Year ended December 31,		
($ per bbl, except as noted)	**2006**	2005	% Change
Oil per barrel			
WTI (US$)	$ **66.22**	$ 56.56	17
Exchange rate (from US$ to Cdn$)	**1.13**	1.21	(7)
WTI expressed in Cdn$	$ **74.83**	$ 68.44	9
Realized pricing before financial derivative instruments			
Light/Medium oil (Cdn$)	$ **63.25**	$ 57.80	9
Natural gas liquids (Cdn$)	$ **57.07**	$ 45.12	26
Natural gas (Cdn$ per mcf)	$ **6.58**	$ 9.01	(27)
Crude oil and natural gas liquids (Cdn$)	$ **63.24**	$ 57.76	9

The increase in crude oil realized pricing reflects higher market prices in 2006, compared to 2005. Production from California properties is generally light, sweet crude that attracts smaller differentials to benchmark prices relative to heavier blends. Production from Wyoming properties primarily acquired through the acquisition of Nautilus on March 2, 2005 is heavier and attracts wider differentials. Production from California properties also receives better prices than Canadian or Wyoming production because of the proximity to refineries and ultimate market. Production from California properties for the year ended December 31, 2006 represented approximately 70 percent of total production while production from Wyoming properties represented approximately 30 percent of total production.

Production

	Year ended December 31,		
USOGP	**2006**	2005	% Change
Daily production - by product			
Crude oil - Light/Medium (bpd)	**7,299**	6,921	5
Natural gas liquids (bpd)	**18**	24	(25)
Natural gas (mcfd)	**2,422**	2,159	12
Oil equivalent (boed) (1)	**7,721**	7,305	6

(1) Provident reports equivalent production converting natural gas to oil on a 6:1 basis.

	Year ended December 31,		
USOGP	**2006**	2005	% Change
Daily Production - by area (boed) (1)			
Los Angeles	**3,901**	3,949	(1)
Santa Maria - Orcutt	**1,491**	1,393	7
Wyoming	**2,329**	1,963	19
	7,721	7,305	6

(1) Provident reports equivalent production converting natural gas to oil on a 6:1 basis.

Production for the year ended December 31, 2006 was 7,721 boed or six percent higher than the year ended December 31, 2005. The increase is primarily attributable to a full year of production from the Wyoming properties acquired in the Nautilus acquisition on March 2, 2005. In total, the Wyoming properties acquired on March 2, 2005 added 2,254 boed to production in the year ended December 31, 2006 (2005 – 1,888 boed). In 2005, the acquired properties added 2,260 boed for the period from acquisition on March 2 to December 31, 2005.

Revenue and royalties

The following table outlines USOGP revenue and royalties by product line. The table excludes revenues earned from operating certain properties ($1.0 million in 2006 and 2005) on behalf of third parties.

USOGP	Year Ended December 31,		
($ 000s, except per boe and mcf amounts)	**2006**	2005	% Change
Oil			
Revenue	**$ 168,954**	$ 146,306	15
Realized loss on financial derivative instruments	**(2,505)**	(16,323)	(85)
Royalties	**(16,546)**	(14,022)	18
Net revenue	**$ 149,903**	$ 115,961	29
Net revenue (per bbl)	**$ 56.27**	$ 45.90	23
Royalties as a percentage of revenue	**9.8%**	9.6%	
Natural gas			
Revenue	**$ 5,820**	$ 7,101	(18)
Royalties	**(761)**	(988)	(23)
Net revenue	**$ 5,059**	$ 6,113	(17)
Net revenue (per mcf)	**$ 5.72**	$ 7.76	(26)
Royalties as a percentage of revenue	**13.1%**	13.9%	
Natural gas liquids			
Revenue	**$ 368**	$ 395	(7)
Royalties	**(8)**	(9)	(11)
Net revenue	**$ 360**	$ 386	(7)
Net revenue (per bbl)	**$ 54.79**	$ 44.05	24
Royalties as a percentage of revenue	**2.2%**	2.4%	
Total			
Revenue	**$ 175,142**	$ 153,802	14
Realized loss on financial derivative instruments	**(2,505)**	(16,323)	(85)
Royalties	**(17,315)**	(15,019)	15
Net revenue	**$ 155,322**	$ 122,460	27
Net revenue (per boe)	**$ 55.12**	$ 45.93	20
Royalties as a percentage of revenue	**9.9%**	9.8%	

Royalty rates in the U.S. are significantly lower than in Canada.

Revenue for the year ended December 31, 2006 was $175.1 million or 14 percent higher than the year ended December 31, 2005. The increase is attributable to the acquisition of the Wyoming properties on March 2, 2005 combined with increased crude oil prices. Net revenue was $155.3 million or 27 percent higher than the $122.5 million of net revenue in 2005. A full year of production in 2006 from the Wyoming properties combined with increased crude oil prices and lower realized losses on financial derivative instruments all contribute to the increase. Royalties as a percentage of revenue for the year ended December 31, 2006 were consistent with royalty rates for the year ended December 31, 2005.

Production expenses

USOGP	Year ended December 31,		
($ 000s, except per boe amounts)	**2006**	2005	% Change
Production expenses	**$ 52,008**	$ 39,513	32
Production expenses (per boe)	**$ 18.45**	$ 14.82	24

Production expenses increased 32 percent to $52.0 million in 2006 compared to $39.5 million in 2005. Production expenses per boe have increased 24 percent to $18.45 in 2006 from $14.82 in 2005. This change reflects both the increase in utilities and other costs and services driven by the high commodity price environment as well as higher operating cost crude oil wells that were returned to production to take advantage of continuing strong crude oil prices.

Operating netback

USOGP	Year ended December 31,		
($ per boe)	**2006**	2005	% Change
USOGP oil equivalent netback per boe			
Gross production revenue	**$ 62.15**	$ 57.68	8
Royalties	**(6.14)**	(5.63)	9
Operating costs	**(18.45)**	(14.82)	24
Field operating netback	**$ 37.56**	$ 37.23	1
Realized loss on financial derivative instruments	**(0.89)**	(6.12)	(85)
Operating netback after realized financial derivative instruments	**$ 36.67**	$ 31.11	18

USOGP operating netbacks remained strong throughout 2006 due to high commodity prices and lower realized losses on financial derivative instruments when compared to 2005 partially offset by increased production costs.

General and administrative

USOGP	Year ended December 31,		
($ 000s, except per boe amounts)	**2006**	2005	% Change
Cash general and administrative	**$ 26,519**	$ 11,490	131
Non-cash unit based compensation	**12,476**	6,098	105
	$ 38,995	$ 17,588	122
Cash general and administrative (per boe)	**$ 9.41**	$ 4.31	118

Cash general and administrative expenses were $26.5 million or $9.41 per boe in 2006, compared to $11.5 million, or $4.31 per boe in 2005. Cash general and administrative expense in 2006 includes $5.0 million payments of incentive plans, representing $1.75 per boe compared to $2.3 million in 2005 or $0.85 per boe. Also included in cash general and administrative expense in 2006 is $1.5 million (2005 – nil) of due diligence expenditures relating to a real estate development project representing $0.53 per boe (2005 – nil). The remaining increase is costs associated with compliance (including costs associated with the implementation of procedures and documentation to be in compliance with U.S. Sarbanes-Oxley Act) and increased staffing levels, as well as legal and consulting costs in connection with the initial public offering of the MLP.

Non-cash unit based compensation increased 105 percent to $12.5 million from $6.1 million in 2005. This increase in incentive plan costs is primarily driven by the initial public offering of the MLP, completed in the fourth quarter of 2006.

Capital expenditures

USOGP		Year ended December 31,		
($ 000s)		2006		2005
Capital expenditures - by category				
Geological, geophysical and land	$	**104**	$	4,608
Drilling, recompletions, and workovers		**30,943**		29,470
Facilities and equipment		**18,486**		18,035
Other capital		**4,804**		784
Total additions	$	**54,337**	$	52,897
Capital expenditures - by area				
Los Angeles		**17,886**		33,848
Santa Maria - Orcutt		**16,579**		8,528
Wyoming		**15,023**		5,183
Other capital		**4,849**		5,338
		54,337		52,897
Property acquisitions	$	**(2,012)**	$	-
Property dispositions	$	**(4)**	$	-

USOGP capital expenditures for the year ended December 31, 2006 totaled $52.3 million including the second quarter adjustment of $2.0 million to reduce accrued acquisition transaction costs related to past acquisitions. Of this total $29.6 million related to drilling, optimization and facility upgrades at West Pico, Santa Fe Springs and Orcutt. $15.0 million was directed at optimization projects in Wyoming, $3.4 million was directed to a land development project initiated in the second quarter and $6.3 million was directed at optimization projects at smaller fields as well as office equipment.

Depletion, depreciation and accretion (DD&A)

USOGP		Year ended December 31,			
($ 000s, except per boe amounts)		2006		2005	% Change
DD&A	$	**31,058**	$	25,553	22
DD&A per boe	$	**11.02**	$	9.58	15

The USOGP's DD&A rate is low due to the long-lived nature of the assets.

On a per boe basis the DD&A rate is up $1.44 or 15 percent from 2005. This is primarily associated with a year end depletion rate adjustment reflecting 2006 capital expenditures as well as changes in reserves.

Recent developments

On January 23, 2007, the MLP completed a purchase of certain oil and gas properties in the Permian Basin of Texas, including related property and equipment, for approximately U.S. $29.0 million. The acquisition was financed through borrowings under the MLP's existing revolving credit facility.

Midstream services and marketing business segment review

Midstream NGL acquisition

The $773 million Midstream NGL Acquisition, which closed on December 13, 2005, included NGL extraction plants, pipelines, storage and fractionation facilities, distribution facilities, and contracts including marketing, supply and transportation arrangements, and NGL marketing infrastructure. This acquisition has extended Provident's involvement in the NGL value chain. Results in 2005 included NGL fee for service, fixed margin extraction, equity margin on marketed NGLs, and margin on crude oil marketing contracts. The crude oil marketing contracts were disposed in May 2005, thus 2006 results include an increase in fees for services, fixed margin extraction and equity margin on marketed NGLs.

The Midstream business

The Midstream business unit extracts, processes, stores, transports and markets natural gas liquids (NGL) for Provident and offers these services to third party customers. The Provident Midstream segment contains three business lines:

a) Empress East
b) Redwater West
c) Commercial Services

a. The Empress East business line is comprised of the following core assets:

- Approximately 2.0 Bcfd of extraction capacity at Empress Alberta. This is the combination of 67.5 percent ownership of the 1.2 Bcfd capacity Provident Empress NGL Extraction plant, 12.4 percent ownership in the 1.1 Bcfd capacity ATCO Plant, 8.3 percent ownership in the 2.4 Bcfd capacity Spectra Plant and 33.0 percent ownership in the 2.7 Bcfd capacity BP Empress 1 Plant.

- 100 percent ownership of a 50,000 bpd debutanizer at Empress Alberta.

- 50 percent ownership in the 130,000 bpd Kerrobert Pipeline and 2.5 mmbbl underground storage facility near Kerrobert, Saskatchewan which facilitates injection into the Enbridge Pipeline System. Along the Enbridge Pipeline System, Provident holds 18.3 percent ownership of a 300,000 barrel Superior Storage staging facility and 18.3 percent ownership of the 6,600 bpd Superior Depropanizer.

- In Sarnia, Ontario, 10.3 percent ownership of an approximately 150,000 bpd fractionator, 1.7 mmbbl of raw product storage capacity and 18 percent of 5.0 mmbbl of finished product storage and rail, truck and pipeline terminalling. An additional 0.5 mmbbls of specification product storage is also available in the Sarnia area.

- A propane distribution terminal at Lynchburg, Virginia.

- A rail car fleet of approximately 350 rail cars.

The income for this business line is primarily driven by the pricing relationship of natural gas at AECO to NGL values in Belvieu. Provident purchases the NGLs from suppliers at Empress at gas values and then extracts the NGLs from the gas at the various straddle plants. Propane, butane and condensate prices trend on a pricing relationship to crude oil. Provident sells this product and other acquired specification product into key market areas such as Ontario, Quebec, and the Eastern Seaboard. The higher the ratio of the WTI crude oil price to the natural gas price at AECO (the fractionation spread ratio "frac spread ratio"), the higher the gross operating margin this business line will typically deliver. There has also, however, historically been a differential between propane, butane and condensate prices and crude oil prices which can change prices received and margins realized for Midstream products separate from frac spread ratio changes. The margin for this business line was $133.7 million in 2006.

b. The Redwater West business line is comprised of the following core assets:

- 100 percent ownership of the Redwater NGL Fractionation Facility, incorporating a 65,000 bpd fractionation, storage and transportation facility that includes 12 pipeline receipt and delivery points, railcar loading facilities with direct access to CN rail and indirect access to CP rail, two propane truck loading facilities, six million gross barrels of salt cavern storage, and a 60,000 bpd condensate rail offloading facility with a 300 railcar storage yard. The facility can process high-sulphur NGL streams and is one of only two ethane-plus fractionation facilities in western Canada capable of extracting ethane from the natural gas liquids stream.

- Approximately 7,000 bpd of leased fractionation and storage capacity at other facilities.

- 43.3 percent direct ownership and 100% control of all products from the 38,500 bpd Younger NGL extraction plant located at Taylor in northeastern British Columbia that supplies local markets and Provident in the greater Fort Saskatchewan area.

- 100 percent ownership of the 565 kilometer proprietary Liquids Gathering System ("LGS") that runs along the Alberta-British Columbia border providing access to a highly active basin for liquids-rich natural gas exploration and exploitation. Provident also has long-term shipping rights on the Pembina Peace Pipeline that extends the product delivery transportation network through to the Redwater fractionation facility.

- A rail car fleet of approximately 450 rail cars.

The income for this business line includes the long term natural gas liquids purchase agreement from Taylor Gas Liquids for its share of the production at the same plant. Further, this business line includes the income generated by the supply and marketing personnel in the Calgary office which includes the purchasing of NGL mix from various producers transporting to Redwater/Ft. Saskatchewan for fractionation and sale to various markets primarily in Western Canada and the Western United States. 2006 margin for this business line was $69.5 million.

c. The Commercial Services business line:

The Commercial Services business line includes services such as fractionation, storage, and loading at Provident's Redwater facility on a fee basis. It also includes pipeline tariff income from Provident's ownership of the Liquids Gathering System in Northwest Alberta which flows into Pembina's pipeline from LaGlace to Redwater. Provident also collects tariff income from its 50% ownership in the Kerrobert Pipeline which transports NGLs from Empress to Kerrobert for injection into the Enbridge pipeline for delivery to Sarnia. Further, Provident owns a debutanizer at its Empress facility, which removes condensate from the NGL mix for sale as a diluent to blend with heavy oil. This service is provided to a major energy company on a long term cost of service basis. Earnings from this business line of the Midstream segment have little direct exposure to market prices volatility and are thus relatively stable. 2006 margin for this business line was $52.8 million.

Long term contracts

At the Redwater facility, a significant portion of the available propane plus capacity is contracted through a long term fee for service arrangement with third parties.

In 2006 Provident commissioned a 60,000 bpd condensate rail off-loading terminal at Redwater, a significant portion of which is under long term contracts with two major energy producers.

The ethane produced from Provident's facilities at Empress and Redwater is largely sold under long term contracts.

Provident also has a long term contract on a cost of service basis for the majority of its 50,000 bbl/d Empress debutantizer facility and a long term contract for 500,000 barrels of specification product storage in the Sarnia area.

Also, see commitments disclosure in note 16 to consolidated financial statements.

Operations – managed NGL volumes

In 2006, Provident Midstream managed approximately 153,020 bpd compared to 64,740 bpd in 2005, an increase of 136 percent. Managed volumes are NGL products that have been purchased or received for further processing and/or sale. The significant increase in 2006 is a result of the Midstream NGL Acquisition.

2006 Midstream business unit results can be summarized as follows:

Year ended December 31, ($ millions)		2006
Empress East Margin	$	133.7
Redwater West Margin		69.5
Commercial Services Margin		52.8
Gross operating margin		256.0
Cash general and administrative expenses and other		(21.0)
Realized loss on financial derivative instruments		(15.4)
Midstream EBITDA		219.6

Revenues

For 2006 product sales and services revenue were $1,764.4 million (2005 - $908.1 million). The significant increase in revenue over 2005 is a result of the Midstream NGL Acquisition, an increase in propane plus prices in the second and third quarters of 2006 over the comparable quarters in 2005, and the commissioning of the condensate loading and terminalling facilities in the second quarter of 2006. Product sales relate to the marketing of NGLs and transportation and fractionation contracts (T&F), while service revenue relates to fees earned through NGL processing, marketing, storage and distribution. The majority of NGL revenues are earned pursuant to both long-term contracts and annual evergreen purchase and sales commitments.

In addition to the increased product sales and service revenue, Midstream revenue was reduced by $15.4 million for the year ended December 31, 2006 (2005 – $2.2 million) due to realized losses on financial derivative instruments. Midstream enters into derivative contracts to assist with margin stabilization on marketed products.

Expenses

For 2006 the cost of goods sold (COGS) was $1,471.2 million (2005 - $786.6 million). Cost of goods sold relates to NGL product sales revenue included in product sales and services revenue. COGS include all costs incurred in the production and purchase of NGL specification product for sale. The majority of the natural gas liquids are purchased pursuant to long-term contracts and annual evergreen purchase commitments. The significant increase in COGS over 2005 is a result of the Midstream NGL Acquisition which has resulted in an increase in managed volumes.

Operating and maintenance expenses were $22.6 million for 2006 (2005 - $36.4 million). Since the third quarter of 2006, costs include operating costs incurred to process NGLs, and provide T&F, and storage and distribution services to third parties. In prior periods, operating costs also included costs incurred at the Younger and Redwater facilities for NGLs Provident had purchased. These costs are now included in the determination of inventory and cost of goods sold, reflecting the integration of operations after the Midstream NGL Acquisition.

General and administrative expenses were $29.9 million in 2006 (2005 - $12.6 million) representing an increase in the scale of segment operations and an increased number of employees since the Midstream NGL Acquisition. As well, there were increased costs for integration and compliance activities, including costs related to the implementation of procedures and documentation in connection with the U.S. Sarbanes-Oxley Act. Interest expense for 2006 was $32.1 million (2005 - $4.9 million) reflecting an increase in capitalization associated with the Midstream NGL Acquisition. Depreciation expense was $49.1 million in 2006 (2005 – $11.8 million) reflecting the larger asset base acquired through the Midstream NGL Acquisition. The majority of the property, plant and equipment are depreciated on a straight-line basis reflecting the long useful life of these assets of 30 to 40 years.

Earnings before interest, taxes, depletion, depreciation, accretion, and other non-cash items ("EBITDA") and cash flow from operations

For 2006 EBITDA increased 211 percent to $219.6 million from $70.7 million in 2005. Annual cash flow increased 178 percent to $184.4 million from $66.3 million in 2005. Through the Midstream NGL Acquisition, Provident has expanded its involvement in the NGL value chain and increased managed volumes by 136 percent to 153,020 bpd, which has made a significant contribution to the overall increase in EBITDA and cash flow. In addition, Midstream EBITDA and cash flow benefited from an increase in propane plus prices in the second and third quarters of 2006 over the comparable quarters in 2005 accompanied by a reduction in associated product costs, mostly due to reduced natural gas prices.

Management uses EBITDA to analyze the operating performance of the Midstream business unit. EBITDA as presented does not have any standardized meaning prescribed by Canadian GAAP and therefore it may not be comparable with the calculation of similar measures for other entities. EBITDA as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP. All references to EBITDA throughout this report are based on earnings before interest, taxes, depletion, depreciation, accretion, and other non-cash items ("EBITDA").

Fractionation spread support program

As part of the Midstream NGL Acquisition, the vendor agreed to provide a near-term fractionation spread support program. The program provides Provident with up to $75 million of support until November 2007 if the fractionation spread ratio is below historic levels. This program is intended to ensure that Provident achieves the long-term average fractionation spread ratio that the NGL business has attained historically through to November 2007. This program is intended to provide consistent and stable cash flow and distributions for Unitholders. In certain circumstances, the vendor will have the ability to recover the amounts provided under the support program until October 31, 2008, if the fractionation spread ratio exceeds historic levels. Provident's long term risk management strategy is focused on locking in fractionation spread margins, with the objective of stabilizing cash flow over the longer term.

The impact of the agreement on the 2006 results was a $5.2 million repayment in the first quarter of 2006, of an amount that was received in the fourth quarter of 2005, resulting in an increase in the cost of goods available for sale in 2006.

Capital expenditures

Midstream capital expenditures for 2006 totaled $66.0 million. $42.0 million of the capital was spent on the new condensate offloading facilities and truck terminals at Redwater. $9.2 million was spent on the initial drilling of two new Redwater storage caverns expected to be completed in 2009, and $11.3 million was spent to acquire an additional 7.5% of the Provident Empress NGL Extraction plant. The remaining $3.5 million relates to sustaining capital requirements.

Foreign ownership

Based on information received from our transfer agent and financial intermediaries in January 2007, an estimated 85 percent of our outstanding trust units are held by non-residents. However, this estimate may not be accurate as it is based on certain assumptions and data from the securities industry that does not have a well-defined methodology to determine the residency of beneficial holders of securities.

The Trust qualifies as a Mutual Fund Trust under the Canadian Income Tax Act because substantially all the value of its asset portfolio is derived from non-taxable Canadian properties, comprised principally of royalties and interest on inter-company debt. Provident monitors on an ongoing basis the value of its asset portfolio to confirm that substantially all of the value of its asset portfolio is derived from non-taxable Canadian properties.

On September 17, 2003 Canadian unitholders approved an amendment to the Trust's Trust Indenture providing that residency restriction provisions need not be enforced while the Trust continues to qualify as a Mutual Fund Trust under Canadian tax legislation. To allow Provident to remain a Mutual Fund Trust and to execute a business plan

that maximizes unitholder returns without regard to the types of assets the Trust may hold, the approved amendment provides for Provident's Board of Directors to have sole discretion to determine whether and when it is appropriate to reduce or limit the number of trust units held by non-residents of Canada.

Critical accounting policies

Provident's accounting policies are described in note 2 to the consolidated financial statements. Certain accounting policies are identified as critical accounting policies because they form an integral part of Provident's financial position. They also require management to make judgments and estimates based on conditions and assumptions that are inherently uncertain. These accounting policies could result in materially different results should the underlying assumptions or conditions change.

Management assumptions are based on Provident's historical experience, management's experience, and other factors that, in management's opinion, are relevant and appropriate. Management assumptions may change over time, as further experience is gained or as operating conditions change.

Details of Provident's critical accounting policies are as follows:

Property, plant and equipment

Provident follows the full cost method of accounting, whereby all costs associated with the acquisition and development of oil and natural gas reserves are capitalized. Utilization of the full cost method of accounting requires the use of management estimates and assumptions for amounts recorded for depletion and depreciation of property, plant and equipment as well as for the ceiling test.

The provision for depletion and depreciation is calculated using the unit of production method based on current production divided by Provident's share of estimated total proved oil and natural gas reserve volumes before royalties. The recoverability of a cost centre is tested by comparing the carrying value of the cost centre to the sum of the undiscounted cash flows expected from the cost centre. If the carrying value is not recoverable the cost centre is written down to its fair value.

Proved reserves are an estimate, under existing reserve evaluation polices, of volumes that can reasonably be expected to be economically recoverable under existing technology and economic conditions. Changes in underlying assumptions or economic conditions could have a material impact on Provident's financial results. To mitigate these risks, management utilizes McDaniel & Associates Consultants Ltd., an independent engineering firm, to evaluate Provident's Canadian reserves. For Provident's U.S. based assets management utilizes Netherland, Sewell & Associates, Inc., an independent engineering firm, to evaluate reserves.

Estimates of future production, oil and natural gas prices and future costs used in the ceiling test are, by their very nature, subject to uncertainty and changes in underlying assumptions could have a material impact on Provident's financial results.

Asset retirement obligation

Under the asset retirement obligation (ARO) standard, the fair value of asset retirement obligations is recorded as a liability on a discounted basis, when incurred. The value of the related assets is increased by the same amount as the liability and depreciated over the useful life of the asset. Over time the liability is adjusted for the change in present value of the liability or as a result of changes to either the timing or amount of the original estimate of undiscounted future cash flows.

Asset retirement obligation requires that management make estimates and assumptions regarding future liabilities and cash flows involving environmental reclamation and remediation. Such assumptions are inherently uncertain and subject to change over time due to factors such as historical experience, changes in environmental legislation or improved technologies. Changes in underlying assumptions, based on the above noted factors, could have a material impact on Provident's financial results.

Recent accounting pronouncements

Convergence of Canadian GAAP with International Financial Reporting Standards

In 2006, Canada's Accounting Standards Board (AcSB) issued a strategic plan that will result in Canadian GAAP, as it applies to publicly accountable entities, being converged with International Financial Reporting Standards over a transitional period. The AcSB is expected to develop and release a detailed implementation plan with a transition period initially indicated to be five years. The Trust will consider the effect that this implementation plan might have on the consolidated financial statements during the transition period.

Accounting changes

In 2006, the CICA released Section 1506 "Accounting Changes" which establishes criteria for changing accounting policies. Under the new section, voluntary changes in accounting policy are only made if they result in the financial statements providing reliable and more relevant information. Changes in accounting policy are applied retroactively unless it is impracticable to do so or the change in accounting policy is made on initial application of a primary source of GAAP, and that primary source of GAAP has specific transitional provisions. All material prior period errors are to be corrected retroactively. This section is effective for interim and annual financial statements for fiscal years beginning on or after January 1, 2007. The Trust does not expect the adoption of this standard to have a material impact on its financial statements.

Capital disclosures

In 2006, the CICA released Section 1535 "Capital disclosures" which addresses the requirements for an entity to disclose qualitative information about its objectives, policies and processes for managing capital. This section also establishes the requirement for an entity to disclose quantitative data about what it regards as capital as well as disclose whether it has complied with any externally imposed capital requirements and, if not, the consequences of such non-compliance. This section is effective for interim and annual financial statements relating to fiscal years beginning on or after October 1, 2007. The Trust is currently evaluating the effect that this standard might have on the consolidated financial statements.

Discontinued operations

In April 2006, the CICA issued EIC abstract 161 "Discontinued Operations" which specifically addresses issues regarding the treatment of interest expense to be allocated to a discontinued operation, general corporate overhead expenses allocated to a discontinued operations, and reporting the results of operations of a component of the enterprise classified as held for sale as discontinued operations if the remaining operations are insignificant. The accounting treatment of the abstract may be applied prospectively and should be applied to all disposal transactions initiated after the date of issue of the abstract. The adoption of this abstract has not had a material impact on the Trust's consolidated financial statements.

Stock-based compensation for employees eligible to retire before the vesting date

In 2006, the CICA issued EIC abstract 162 "Stock-based compensation for employees eligible to retire before the vesting date." In this abstract, the CICA addresses the situation if an employee is eligible to receive a reward after the employee has retired and is no longer providing service to the entity. In this situation, the abstract states that the expense associated with the reward should be recognized over the period from the grant date to the date the employee becomes eligible to retire, or, in situations where the employee is eligible to retire before the grant date, the entire expense should be recognized on the grant date. The accounting treatment of this abstract should be applied retroactively, with restatement of prior periods in financial statements issued for interim and annual periods ending on or after December 31, 2006. The adoption of this abstract has not had a material impact on the Trust's consolidated financial statements.

Variable interest entities

In 2006, the CICA issued EIC abstract 163 "Determining the variability to be considered in applying AcG-15" which provides guidance on how an entity should determine the variability to be considered in applying AcG-15-Consolidation of Variable Interest Entities. The abstract is to be applied prospectively to all entities with which an enterprise first becomes involved, and to all entities previously required to be analyzed under AcG-15 when a

reconsideration event has occurred, beginning the first day of the first interim or annual reporting period beginning on or after January 1, 2007. The Trust does not expect the adoption of this abstract to have a material impact on its financial statements.

Financial Instruments, Hedges and Comprehensive Income

In 2005, the CICA issued Section 3855 "Financial instruments-recognition and measurement," Section 3865 "Hedges," and Section 1530 "Comprehensive Income." Under these Sections, standards for recognizing and measuring financial assets, financial liabilities and non-financial derivatives have been established. The standards will require the majority of derivatives to be classified as held for trading and will be measured at fair value with gains and losses recognized in net income in the periods in which they arise unless they are part of a hedging relationship. For hedges, the existing requirements for hedge accounting under Accounting Guideline 13 "Hedging relationships" are maintained, with the majority of hedging relationships being stated at fair value with a gain or loss from remeasuring the foreign currency component of its carrying amount being recognized in net income in the period of change together with the offsetting loss or gain on the hedged item attributable to the hedged risk. These new standards also require an entity to present comprehensive income and its components, as well as net income, in its financial statements. This will include certain gains or losses, including foreign currency translation and other amounts arising from changes in fair value. These Sections apply to interim and annual financial statements relating to fiscal years beginning on or after October 1, 2006. The Trust is currently evaluating the effect that these standards might have on the consolidated financial statements.

In conjunction with the above standards, the CICA issued Section 3862 "Financial Instruments- Disclosures" and Section 3863 "Financial Instruments-Presentation." Section 3862 requires entities to provide disclosures in their financial statements that enable users to evaluate the significance of financial instruments to the entity's financial position and performance. It also requires that entities disclose the nature and extent of risks arising from financial instruments and how the entity manages those risks. Section 3863 establishes presentation guidelines for financial instruments and non-financial derivatives and addresses the classification of financial instruments, from the perspective of the issuer, between liabilities and equity, the classification of related interest, dividends, losses and gains, and circumstances in which financial assets and financial liabilities are offset. These two sections are effective for annual and interim periods beginning on or after October 1, 2007. The Trust is currently evaluating the effect that these standards might have on the consolidated financial statements.

Equity

In 2005, the CICA issued Section 3251 "Equity". This Section replaces Section 3250 "Surplus" and establishes standards for the presentation of equity and changes in equity during the reporting period. The Section requires an entity to present separately each of the changes in equity during the period, including comprehensive income, as well as components of equity at the end of the period. This Section applies to interim and annual financial statements relating to fiscal years beginning on or after October 1, 2006. The Trust is currently evaluating the effect that this standard might have on the consolidated financial statements.

Business risks

The trust industry is subject to risks that can affect the amount of cash flow available for distribution to unitholders, and the ability to grow. These risks include but are not limited to:

- capital markets risk and the ability to finance future growth; and
- the impact of Canadian governmental regulation on Provident, including the effect of proposed taxation of trust distributions.

The oil and natural gas industry is subject to numerous risks that can affect the amount of cash flow available for distribution to unitholders and the ability to grow. These risks include but are not limited to:

- fluctuations in commodity price, exchange rates and interest rates;
- government and regulatory risk in respect of royalty and income tax regimes;
- operational risks that may affect the quality and recoverability of reserves;
- geological risk associated with accessing and recovering new quantities of reserves;

- transportation risk in respect of the ability to transport oil and natural gas to market;
- marketability of oil and natural gas;
- the ability to attract and retain employees; and
- environmental, health and safety risks.

The midstream industry is also subject to risks that can affect the amount of cash flow available for distribution to unitholders and the ability to grow. These risks include but are not limited to:

- operational matters and hazards including the breakdown or failure of equipment, information systems or processes, the performance of equipment at levels below those originally intended, operator error, labour disputes, disputes with owners of interconnected facilities and carriers and catastrophic events such as natural disasters, fires, explosions, fractures, acts of eco-terrorists and saboteurs, and other similar events, many of which are beyond the control of the Trust or Provident;
- the Midstream NGL assets are subject to competition from other gas processing plants, and the pipelines and storage, terminal and processing facilities are also subject to competition from other pipelines and storage, terminal and processing facilities in the areas they serve, and the gas products marketing business is subject to competition from other marketing firms;
- exposure to commodity price fluctuations;
- the ability to attract and retain employees;
- regulatory intervention in determining processing fees and tariffs; and
- reliance on significant customers.

Provident strives to minimize these business risks by:

- employing and empowering management and technical staff with extensive industry experience and providing competitive remuneration;
- adhering to a strategy of acquiring, developing and optimizing quality, low-risk reserves in areas where we have technical and operational expertise;
- developing a diversified, balanced asset portfolio that generally offers developed operational infrastructure, year-round access and close proximity to markets;
- adhering to a consistent and disciplined Commodity Price Risk Management Program to mitigate the impact that volatile commodity prices have on cash flow available for distribution;
- marketing crude oil and natural gas to a diverse group of customers, including aggregators, industrial users, well-capitalized third-party marketers and spot market buyers;
- marketing natural gas liquids and related services to selected, credit worthy customers at competitive rates;
- maintaining a low cost structure to maximize cash flow and profitability;
- maintaining prudent financial leverage and developing strong relationships with the investment community and capital providers;
- adhering to strict guidelines and reporting requirements with respect to environmental, health and safety practices; and
- maintaining an adequate level of property, casualty, comprehensive and directors' and officers' insurance coverage.

Unit trading activity

The following table summarizes the unit trading activity of the Provident units for the four quarters ended December 31, 2006 on both the Toronto Stock Exchange and the New York Stock Exchange:

	Q1		Q2		Q3		Q4
TSE – PVE.UN (Cdn$)							
High	$	13.70	$ 14.31	$	14.50	$	13.85
Low	$	11.79	$ 12.87	$	12.07	$	10.05
Close	$	13.04	$ 14.00	$	13.02	$	12.84
Volume (000s)		23,113	29,205		43,411		35,081
NYSE – PVX (US$)							
High	$	11.66	$ 12.99	$	13.04	$	12.16
Low	$	10.24	$ 11.16	$	10.81	$	9.00
Close	$	11.32	$ 12.37	$	11.75	$	10.92
Volume (000s)		36,038	29,175		33,378		35,480

Additional information

Additional information concerning Provident can be accessed under Provident's public filings at www.sedar.com and on Provident's website at www.providentenergy.com.

Selected annual financial measures

($ 000s except per unit data)		**2006**		2005		2004
Revenue (net of royalties and financial derivative instruments)	**$**	**2,187,253**	$	1,360,274	$	1,109,857
Net income		**140,920**		96,926		21,225
Net income per unit-basic		**0.72**		0.61		0.19
Net income per unit-diluted		**0.72**		0.61		0.19
Total assets		**3,435,839**		2,792,270		1,813,582
Long-term financial liabilities [1]		**1,132,494**		930,756		472,712
Declared Distributions per unit	**$**	**1.44**	$	1.44	$	1.44

[1] Includes long-term debt, asset retirement obligation, long-term financial derivative instruments and other long-term liabilities.

Quarterly table

($ 000s except for per unit and operating amounts)	2006				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Annual Total
Financial - consolidated					
Revenue	$ 553,706	$ 424,439	$ 661,022	$ 548,086	$ 2,187,253
Cash flow	$ 78,906	$ 110,990	$ 120,089	$ 122,679	$ 432,664
Net income (loss)	$ 24,200	$ 21,371	$ 120,850	$ (25,501)	$ 140,920
Net income (loss) per unit - basic	$ 0.13	$ 0.11	$ 0.61	$ (0.12)	$ 0.72
Net income (loss) per unit - diluted	$ 0.13	$ 0.11	$ 0.58	$ (0.12)	$ 0.72
Unitholder distributions	$ 68,350	$ 68,572	$ 70,970	$ 75,573	$ 283,465
Distributions per unit	$ 0.36	$ 0.36	$ 0.36	$ 0.36	$ 1.44
Oil and gas production					
Cash revenue	$ 114,020	$ 125,744	$ 116,682	$ 125,135	$ 481,581
Earnings before interest, DD&A, taxes and other non-cash items	$ 64,313	$ 77,698	$ 67,750	$ 66,497	$ 276,258
Cash flow	$ 52,813	$ 71,867	$ 61,471	$ 62,147	$ 248,298
Net income (loss)	$ 36,484	$ 25,980	$ 38,117	$ (14,530)	$ 86,051
Midstream services and marketing					
Cash revenue	$ 474,515	$ 367,624	$ 459,603	$ 447,244	$ 1,748,986
Earnings before interest, DD&A, taxes and other non-cash items	$ 32,813	$ 46,438	$ 65,958	$ 74,422	$ 219,631
Cash flow	$ 26,093	$ 39,123	$ 58,618	$ 60,532	$ 184,366
Net (loss) income	$ (12,284)	$ (4,609)	$ 82,733	$ (10,971)	$ 54,869
Operating					
Oil and gas production					
Light/medium oil (bpd)	14,541	13,923	13,955	13,899	14,114
Heavy oil (bpd)	2,506	2,011	2,004	1,838	2,057
Natural gas liquids (bpd)	1,527	1,475	1,326	1,345	1,419
Natural gas (mcfd)	78,274	80,084	80,991	100,029	84,891
Oil equivalent (boed)	31,620	30,756	30,784	33,753	31,739
(Cdn $)					
Average selling price net of transportation expense					
Light/medium oil per bbl (before realized financial derivative instruments)	$ 54.80	$ 69.76	$ 62.95	$ 54.59	$ 60.32
Light/medium oil per bbl (including realized financial derivative instruments)	$ 53.40	$ 68.00	$ 60.72	$ 55.56	$ 59.22
Heavy oil per bbl (before realized financial derivative instruments)	$ 22.87	$ 50.42	$ 48.15	$ 25.82	$ 36.80
Heavy oil per bbl (including realized financial derivative instruments)	$ 22.82	$ 50.42	$ 48.15	$ 25.82	$ 36.78
Natural gas liquids per barrel	$ 53.91	$ 54.20	$ 52.03	$ 47.49	$ 51.98
Natural gas per mcf (before realized financial derivative instruments)	$ 8.00	$ 6.10	$ 5.88	$ 6.71	$ 6.66
Natural gas per mcf (including realized financial derivative instruments)	$ 7.85	$ 6.41	$ 6.24	$ 7.12	$ 6.91
Midstream services and marketing					
Managed NGL volumes (bpd)	163,420	158,941	144,279	145,732	153,020

Quarterly table

($ 000s except for per unit and operating amounts)	2005				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Annual Total
Financial - consolidated					
Revenue	$ 322,023	$ 300,504	$ 295,060	$ 442,687	$ 1,360,274
Cash flow	$ 64,137	$ 64,435	$ 86,318	$ 96,298	$ 311,188
Net income (loss)	$ (2,783)	$ 26,822	$ 18,386	$ 54,501	$ 96,926
Net income (loss) per unit - basic and diluted	$ (0.02)	$ 0.17	$ 0.11	$ 0.32	$ 0.61
Unitholder distributions	$ 51,734	$ 57,001	$ 59,333	$ 62,646	$ 230,714
Distributions per unit	$ 0.36	$ 0.36	$ 0.36	$ 0.36	$ 1.44
Oil and gas production					
Cash revenue	$ 100,447	$ 104,478	$ 124,073	$ 117,710	$ 446,708
Earnings before interest, DD&A, taxes and other non-cash items	$ 59,262	$ 63,584	$ 81,670	$ 73,976	$ 278,492
Cash flow	$ 48,937	$ 53,868	$ 74,139	$ 68,006	$ 244,950
Net income (loss)	$ (15,046)	$ 14,681	$ 10,702	$ 30,437	$ 40,774
Midstream services and marketing					
Cash revenue	$ 245,338	$ 186,635	$ 180,875	$ 293,034	$ 905,882
Earnings before interest, DD&A, taxes and other non-cash items	$ 16,380	$ 11,765	$ 12,978	$ 29,566	$ 70,689
Cash flow	$ 15,200	$ 10,567	$ 12,179	$ 28,292	$ 66,238
Net income	$ 12,263	$ 12,141	$ 7,684	$ 24,064	$ 56,152
Operating					
Oil and gas production					
Light/medium oil (bpd)	14,388	15,891	15,583	14,051	14,979
Heavy oil (bpd)	5,547	4,644	4,075	3,195	4,358
Natural gas liquids (bpd)	1,756	1,454	1,523	1,653	1,596
Natural gas (mcfd)	80,466	79,126	75,523	73,363	77,095
Oil equivalent (boed)	35,102	35,177	33,768	31,126	33,782
(Cdn $)					
Average selling price net of transportation expense					
Light/medium oil per bbl (before realized financial derivative instruments)	$ 49.32	$ 51.20	$ 62.95	$ 55.31	$ 54.69
Light/medium oil per bbl (including realized financial derivative instruments)	$ 40.93	$ 42.18	$ 49.82	$ 42.52	$ 43.90
Heavy oil per bbl (before realized financial derivative instruments)	$ 25.85	$ 26.03	$ 46.74	$ 28.62	$ 31.33
Heavy oil per bbl (including realized financial derivative instruments)	$ 25.78	$ 26.03	$ 46.74	$ 28.62	$ 31.31
Natural gas liquids per barrel	$ 45.30	$ 47.75	$ 54.27	$ 49.44	$ 49.09
Natural gas per mcf (before realized financial derivative instruments)	$ 6.76	$ 7.29	$ 8.43	$ 11.44	$ 8.43
Natural gas per mcf (including realized financial derivative instruments)	$ 6.74	$ 7.13	$ 8.03	$ 11.22	$ 8.23
Midstream services and marketing					
Managed NGL volumes (bpd)	61,590	58,200	61,760	77,100	64,740

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Provident is responsible for establishing and maintaining adequate internal control over financial reporting for the Trust. Under the supervision of our Chief Executive Officer and our Chief Financial Officer we have conducted an evaluation of the effectiveness of our internal control over financial reporting based on the Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our assessment, we have concluded that as of December 31, 2006, our internal control over financial reporting was effective.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management's assessment of the effectiveness of the Trust's internal control over financial reporting as of December 31, 2006, has been audited by PricewaterhouseCoopers LLP, independent auditors, as stated in their report which appears herein.

Thomas W. Buchanan
Chief Executive Officer

Mark N. Walker
Chief Financial Officer

Calgary, Alberta
March 7, 2007

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

The management of Provident is responsible for the information included in this Annual Report. The financial statements have been prepared in accordance with accounting principles generally accepted in Canada and in accordance with accounting policies detailed in the notes to the financial statements. Where necessary, the statements include amounts based on management's informed judgments and estimates. Financial information in the Annual Report is consistent with that presented in the financial statements.

PricewaterhouseCoopers LLP, Chartered Accountants, appointed by the unitholders, have audited the financial statements and conducted a review of internal accounting policies and procedures to the extent required by generally accepted auditing standards, and performed such tests as they deemed necessary to enable them to express an opinion on the financial statements.

The Board of Directors, through its Audit Committee, is responsible for ensuring that management fulfills its responsibility for financial reporting and internal control. The Audit Committee is composed of three independent directors. The Audit Committee reviews the financial content of the Annual Report and reports its findings to the Board of Directors for its consideration in approving the financial statements.

Thomas W. Buchanan
Chief Executive Officer

Mark N. Walker
Chief Financial Officer

Calgary, Alberta
March 7, 2007

PricewaterhouseCoopers LLP
Chartered Accountants
111 5th Avenue SW, Suite 3100
Calgary, Alberta
Canada T2P 5L3
Telephone +1 (403) 509 7500
Facsimile +1 (403) 781 1825

Independent Auditors' Report

To the Unitholders of Provident Energy Trust

We have completed an integrated audit of the consolidated financial statements and internal control over financial reporting of Provident Energy Trust (the Trust) as of December 31, 2006 and an audit of its December 31, 2005 consolidated financial statements. Our opinions, based on our audits, are presented below.

Consolidated financial statements

We have audited the accompanying consolidated balance sheets of the Trust as at December 31, 2006 and 2005, and the related consolidated statements of operations and accumulated income and cash flows for the years then ended. These financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audit of the Trust's financial statements as at December 31, 2006 and for the year then ended in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). We conducted our audit of the Trust's financial statements as at December 31, 2005 and for the year then ended in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. A financial statement audit also includes assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Trust as at December 31, 2006 and 2005 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

PRICEWATERHOUSECOOPERS

Internal control over financial reporting

We have also audited management's assessment, included in the Management's Report on Internal Control Over Financial Reporting to the unitholders, that the Trust maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Trust's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Trust's internal control over financial reporting based on our audit.

We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PRICEWATERHOUSECOOPERS

In our opinion, management's assessment that the Trust maintained effective internal control over financial reporting as at December 31, 2006 is fairly stated, in all material respects, based on criteria established in Internal Control — Integrated Framework issued by the COSO. Furthermore, in our opinion, the Trust maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006 based on criteria established in Internal Control — Integrated Framework issued by the COSO.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta
March 7, 2007

Comments by Auditor on Canada – U.S. reporting differences

In the United States, reporting standards for auditors require the addition of an explanatory paragraph (following the opinion paragraph) when there is change in accounting principles that has a material effect on the comparability of the Trust's financial statements, such as the changes described in Note 18 to the Consolidated Financial Statements. Our report is expressed in accordance with Canadian reporting standards which do not require a reference to such a change in accounting principles in the auditors' report when the change is properly accounted for and adequately disclosed in the financial statements.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta
March 7, 2007

PROVIDENT ENERGY TRUST
CONSOLIDATED BALANCE SHEETS
Canadian dollars (000s)

	As at December 31, 2006	As at December 31, 2005
Assets		
Current assets		
Cash and cash equivalents	$ **10,302**	$ 32,113
Accounts receivable	**270,135**	267,246
Petroleum product inventory	**85,868**	110,638
Prepaid expenses	**16,381**	14,326
Financial derivative instruments (note 14)	**43,337**	-
	426,023	424,323
Cash reserve for future site reclamation (note 15)	-	1,872
Investments	**4,320**	3,758
Deferred financing charges	**12,351**	14,710
Property, plant and equipment (note 5)	**2,333,537**	1,702,689
Intangible assets (note 6)	**193,592**	215,850
Goodwill (note 3)	**431,353**	429,068
Long-term financial derivative instruments (note 14)	**34,663**	-
	$ **3,435,839**	$ 2,792,270
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	$ **295,003**	$ 309,704
Cash distributions payable	**21,506**	20,644
Distributions payable to non-controlling interests	**677**	452
Financial derivative instruments (note 14)	**53,068**	14,149
	370,254	344,949
Long-term debt - revolving term credit facilities (note 7)	**702,993**	586,597
Long-term debt - convertible debentures (note 7)	**285,792**	298,007
Asset retirement obligation (note 9)	**49,614**	41,133
Long-term financial derivative instruments (note 14)	**77,790**	-
Other long-term liabilities (note 12)	**16,305**	5,019
Future income taxes (note 13)	**309,006**	91,595
Non-controlling interests (note 10)		
USOGP operations	**81,111**	11,885
Exchangeable shares	-	8,259
Unitholders' equity		
Unitholders' contributions (note 11)	**2,254,048**	1,971,707
Convertible debentures equity component	**18,522**	19,301
Contributed surplus (note 12)	**1,315**	1,675
Cumulative translation adjustment	**(42,294)**	(41,785)
Accumulated income	**238,208**	97,288
Accumulated cash distributions	**(926,825)**	(643,360)
	1,542,974	1,404,826
	$ **3,435,839**	$ 2,792,270

On behalf of the Board of Directors:

M.H. (Mike) Shaikh, CA
Director

Thomas W. Buchanan, CA
Director

PROVIDENT ENERGY TRUST

CONSOLIDATED STATEMENT OF OPERATIONS AND ACCUMULATED INCOME

Canadian dollars (000s except per unit amounts)

	Year ended December 31, 2006	2005
Revenue (note 8)		
Revenue	$ **2,244,107**	$ 1,419,450
Realized loss on financial derivative instruments	**(13,540)**	(66,860)
Unrealized (loss) gain on financial derivative instruments	**(43,314)**	7,684
	2,187,253	1,360,274
Expenses		
Cost of goods sold	**1,471,171**	786,564
Production, operating and maintenance	**172,253**	171,193
Transportation	**19,786**	6,932
Depletion, depreciation and accretion	**249,139**	193,236
General and administrative (note 12)	**97,288**	51,361
Interest on bank debt	**34,666**	10,875
Interest and accretion on convertible debentures	**23,919**	19,643
Amortization of deferred financing charges	**3,854**	1,409
Foreign exchange gain and other	**(2,319)**	(3,244)
Gain on sale of assets (note 4)	-	(5,188)
	2,069,757	1,232,781
Income before taxes and non-controlling interests	**117,496**	127,493
Capital tax expense	**1,314**	4,780
Current and withholding taxes	**5,829**	5,628
Future income tax (recovery) expense (note 13)	**(34,316)**	17,793
	(27,173)	28,201
Net income before non-controlling interests	**144,669**	99,292
Non-controlling interests (note 10)		
USOGP operations	**2,995**	1,596
Exchangeable shares	**754**	770
Net income	**140,920**	96,926
Accumulated income, beginning of year	$ **97,288**	$ 362
Accumulated income, end of year	$ **238,208**	$ 97,288
Net income per unit – basic	$ **0.72**	$ 0.61
Net income per unit – diluted	$ **0.72**	$ 0.61

PROVIDENT ENERGY TRUST
CONSOLIDATED STATEMENT OF CASH FLOWS
Canadian Dollars (000s)

	Year ended December 31, 2006	2005
Cash provided by operating activities		
Net income for the year	$ **140,920**	$ 96,926
Add (deduct) non-cash items:		
Depletion, depreciation and accretion	**249,139**	193,236
Debenture accretion and amortization of deferred charges	**6,357**	4,090
Non-cash unit based compensation (notes 12 and 17)	**23,083**	9,753
Unrealized loss (gain) on financial derivative instruments (note 8)	**43,314**	(7,684)
Unrealized foreign exchange loss (gain) and other	**418**	(356)
Future income tax (recovery) expense (note 13)	**(34,316)**	17,793
Net income attributable to non-controlling interests	**3,749**	2,366
Equity in loss of investee	-	252
Gain on sale of assets (note 4)	-	(5,188)
Cash flow from operations before changes in working capital and site restoration expenditures	**432,664**	311,188
Site restoration expenditures (note 15)	**(4,622)**	(2,481)
Change in non-cash operating working capital	**(13,693)**	(51,344)
	414,349	257,363
Cash provided by financing activities		
Increase in long-term debt	**117,385**	325,771
Declared distributions to unitholders	**(283,465)**	(230,714)
Declared distributions to non-controlling interests	**(6,523)**	(3,360)
Issue of trust units, net of issue costs	**257,076**	395,805
Contributions by non-controlling interests (note 10)	**135,829**	-
Issue of debentures, net of issue costs	-	239,822
Redemption of debentures, net of costs	-	(2,997)
Change in non-cash financing working capital	**(154)**	(50)
	220,148	724,277
Cash used for investing activities		
Capital expenditures	**(190,433)**	(156,499)
Acquisition of Midstream NGL business (note 3)	**(1,036)**	(772,303)
Acquisition of Nautilus	-	(91,420)
Increase in investment	-	(1,010)
Oil and gas property acquisitions (note 3)	**(480,357)**	(586)
(Payments) proceeds from property dispositions	**(1,268)**	45,100
Proceeds on sale of assets (notes 3 and 4)	**11,517**	29,295
Reclamation fund contributions	**(2,750)**	(2,899)
Reclamation fund withdrawals (note 15)	**4,622**	2,481
Payment of financial derivative instruments	-	(7,192)
Change in non-cash investing working capital	**3,397**	5,262
	(656,308)	(949,771)
(Decrease) increase in cash and cash equivalents	**(21,811)**	31,869
Cash and cash equivalents beginning of year	**32,113**	244
Cash and cash equivalents end of year	$ **10,302**	$ 32,113
Supplemental disclosure of cash flow information		
Cash interest paid including debenture interest	$ **56,036**	$ 23,946
Cash taxes paid	$ **9,601**	$ 12,026

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

(Tabular amounts in Cdn$ 000's, except unit and per unit amounts)

December 31, 2006

1. Structure of the Trust

Provident Energy Trust (the "Trust") is an open-end unincorporated investment trust created under the laws of Alberta pursuant to a trust indenture dated January 25, 2001, amended from time to time. The beneficiaries of the Trust are the unitholders. The Trust was established to hold, directly and indirectly, all types of petroleum and natural gas and energy related assets, including without limitation facilities of any kind, oil sands interests, electricity or power generating assets and pipeline, gathering, processing and transportation assets. The Trust commenced operations March 6, 2001.

Cash flow is provided to the Trust from properties owned and operated by Provident Energy Ltd. and directly and indirectly owned subsidiaries of the Trust ("Provident"). Cash flow is paid from Provident to the Trust by way of royalty payments, interest payments and principal debt repayments. The cash payments received by the Trust are subsequently distributed to the unitholders monthly.

2. Significant accounting policies

(i) Principles of consolidation and investments

The consolidated financial statements include the accounts of the Trust and Provident, including the consolidated accounts of all wholly and partially owned subsidiaries, and are presented in accordance with Canadian generally accepted accounting principles. Investments are accounted for using the cost method. Certain comparative numbers have been restated to conform with the current year presentation.

(ii) Financial derivative instruments

All derivative financial instruments are recorded on the balance sheet at fair value and changes in fair value are recognized in income as unrealized gains or losses on financial derivative instruments in the period in which the change occurs. Actual gains or losses are recorded as realized gains or losses on financial derivative instruments in the period that the instrument is settled.

(iii) Cash and cash equivalents

Cash and cash equivalents include short-term investments, such as money market deposits or similar type instruments, with an original maturity of three months or less when purchased.

(iv) Property, plant & equipment and intangible assets

The Trust follows the full cost method of accounting for oil and natural gas exploration and development activities, whereby all costs associated with the acquisition and development of oil and natural gas reserves are capitalized. Such costs include lease acquisition, lease rentals on non-producing properties, geological and geophysical activities, drilling of productive and non-productive wells, and tangible well equipment. Gains or losses on the disposition of oil and gas properties are not recognized unless the resulting change to the depletion and depreciation rate is 20 percent or more. All other property, plant and equipment, including midstream assets, are recorded at cost. Expenditures relating to renewals or betterments that improve the productive capacity or extend the life of property, plant and equipment are capitalized. Maintenance and repairs are expensed as incurred. Products required for line-fill and cavern bottoms are presented as part of property, plant and equipment and are stated at the lower of historic cost and net realizable value and are not depreciated.

a) Depletion, depreciation and accretion

The provision for depletion and depreciation for oil and natural gas assets is calculated using the unit-of-production method based on current production divided by the Trust's share of estimated total proved oil and natural gas reserve volumes, before royalties. Production and reserves of

natural gas and associated liquids are converted at the energy equivalent ratio of 6,000 cubic feet of natural gas to one barrel of oil. In determining its depletion base, the Trust includes estimated future costs for developing proved reserves, and excludes estimated salvage values of tangible equipment and the cost of unproved properties.

Midstream facilities, including natural gas liquids storage facilities and natural gas liquids processing and extraction facilities are carried at cost and depreciated on a straight-line basis over the estimated service lives of the assets, which range from 30 to 40 years. Intangible assets are amortized over the estimated useful lives of the assets, which range from two to 15 years. Capital assets related to pipelines are carried at cost and depreciated using the straight-line method over their economic lives.

b) Ceiling test

Oil and natural gas assets accounted for using the full cost method are subject to a ceiling test. The ceiling test calculation is performed by comparing the carrying value of the cost centre to the sum of the undiscounted proved reserve cash flows expected from the cost centre by country using future price estimates. If the carrying value is not recoverable, the cost centre is written down to its fair value. Fair value is determined by the future cash flows from the proved plus probable reserves discounted at the Trust's risk free interest rate. Any excess carrying value of the assets on the balance sheet above fair value would be recorded in depletion, depreciation and accretion expense as a permanent impairment.

(v) **Joint Venture**

Provident conducts many of its activities through joint ventures and the accounts reflect only Provident's proportionate interest in such activities.

(vi) **Inventory**

Inventories of products are valued at the lower of average cost and net realizable value based on market prices.

(vii) **Goodwill**

Goodwill, which represents the excess of cost of an acquired enterprise over the net of the amounts assigned to assets acquired and liabilities assumed, is assessed at least annually for impairment. To assess impairment, the fair value of the reporting unit is determined and compared to the book value of the reporting unit. If the fair value is less than the book value, then a second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the reporting unit's assets and liabilities from the fair value of the reporting unit to determine the implied fair value of goodwill and comparing that amount to the book value of the reporting unit's goodwill. Any excess of the book value of goodwill over the implied fair value of goodwill is the impaired amount. Goodwill is not amortized.

(viii) **Asset retirement obligation**

Under the asset retirement obligation ("ARO") standard the fair value of a liability for an ARO is recorded in the period where a reasonable estimate of the fair value can be determined. When the liability is recorded, the carrying amount of the related asset is increased by the same amount of the liability. The asset recorded is depleted over the useful life of the asset. Additions to asset retirement obligations due to the passage of time are recorded as accretion expense. Actual expenditures incurred are charged against the obligation.

(ix) **Unit based compensation**

The Trust uses the fair value method of valuing compensation expense associated with the Trust's unit option plan. Provident has applied this method to options issued after January 1, 2003, the effective date for implementing stock based compensation. Under the fair value method the amount to be recognized as expense is determined at the time the options are issued and is deferred and recognized in earnings over the vesting period of the options with a corresponding increase in contributed surplus.

The Trust has established other unit based compensation plans whereby notional units are granted to employees. The fair value of these notional units is estimated and recorded as an expense to non-cash unit based compensation (included in general and administrative expenses) with an offsetting amount to accrued liabilities. A realization of the expense and a resulting reduction in cash provided by operating activities occurs when a cash payment is made.

(x) **Trust unit calculations**

The Trust applies the treasury stock method to determine the dilutive effect of trust unit rights and trust unit options. Under the treasury stock method, outstanding and exercisable instruments that will have a dilutive effect are included in per unit - diluted calculations, ordered from most dilutive to least dilutive.

The dilutive effect of exchangeable shares and convertible debentures is determined using the "if-converted" method whereby the outstanding exchangeables and debentures at the end of the period are assumed to have been exchanged or converted at the beginnning of the period or at the time of issue if issued during the year. Amounts charged to income or loss relating to the outstanding exchangeable shares and debentures are added back to net income for the diluted calculation. The units issued upon exchange or conversion are included in the denominator of per unit - basic calculations from the date of issue.

(xi) **Income taxes**

Provident follows the liability method for calculating income taxes. Differences between the amounts reported in the financial statements of the corporate subsidiaries and their respective tax bases are applied to tax rates in effect to calculate the future tax liability. The effect of any change in income tax rates is recognized in the current period income.

The Trust is a taxable entity under the Income Tax Act (Canada) and is taxable only on income that is not distributed or distributable to the unitholders. As the Trust distributes all of its taxable income to the unitholders and meets the requirements of the Income Tax Act (Canada) applicable to the Trust, no provision for income taxes has been made in the Trust.

(xii) **Revenue recognition**

Revenue associated with the sales of Provident's natural gas, natural gas liquids ("NGLs") and crude oil owned by Provident is recognized when title passes from Provident to its customer.

Marketing revenues and purchased product are recorded on a gross basis when Provident takes title to product and has the risks and rewards of ownership.

Revenues associated with the services provided where Provident acts as agent are recorded on a net basis when the services are provided. Revenues associated with the sale of natural gas liquids storage services are recognized when the services are provided.

(xiii) **Foreign currency translation**

The accounts of self-sustaining foreign operations are translated using the current rate method, whereby assets and liabilities are translated at period-end exchange rates, while revenue and expenses are translated using average rates for the period. Translation gains and losses related to self-sustaining operations are deferred and included as a separate component of unitholders' equity.

The accounts of integrated foreign operations are translated using the temporal method, under which monetary assets and liabilities are translated at the period-end exchange rate, other assets and liabilities at the historical rates, and revenues and expenses at the rates for the period, except depreciation, depletion and accretion which is translated on the same basis as the related assets. Translation gains and losses are included in income in the period in which they arise.

(xiv) **Use of estimates**

The preparation of financial statements requires management to make estimates based on currently available information. Actual results could differ from those estimated. In particular, management makes estimates for amounts recorded for depletion and depreciation of the property, plant and equipment, and asset retirement obligation. The ceiling test uses factors such as estimated reserves, production rates, estimated future petroleum and natural gas prices and future costs. Due to the inherent limitations in metering and the physical properties of storage caverns and pipelines, the determination of precise volumes of natural gas liquids held in inventory at such locations is subject to estimation. Actual inventories of natural gas liquids can only be determined by draining of the caverns. By their very nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of future periods could be material.

The estimation of oil and gas reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, estimated commodity prices, and the timing of future expenditures. The Trust expects reserve estimates to be revised based on the results of future drilling activity, testing, production levels, and economics of recovery based on cash flow forecasts.

3. Acquisitions

i) Acquisition of Rainbow assets

On August 31, 2006 Provident acquired a package of natural gas producing assets in the Rainbow and Peace River Arch areas of northwestern Alberta. The assets provide daily production of approximately 5,500 barrels of oil equivalent, over 90 percent of which is natural gas, and over 200 identified drilling locations. The transaction was accounted for as an asset purchase with the allocation of the purchase price as follows:

Net assets acquired and liabilities assumed		
Property, plant and equipment	$	660,427
Asset retirement obligation		(1,903)
Future income taxes		(185,726)
	$	472,798
Consideration		
Acquisition costs	$	500
Cash		472,298
	$	472,798

The acquisition was financed by the issuance of 16,325,000 units at $13.85 per unit and Provident's credit facilities.

ii) Acquisition of Midstream NGL assets

On December 13, 2005 Provident acquired midstream business assets (the Midstream NGL Acquisition) from EnCana Corporation by way of the purchase of partnership interests, corporations and assets. The business comprises NGL extraction plants, pipelines, storage and fractionation facilities, distribution facilities, contracts including supply and transportation arrangements, and ownership of Kinetic Resources, two partnerships which perform NGL marketing services including Kinetic's interests in a distribution terminal and leases on approximately 700 rail cars. The transaction was accounted for using the purchase method with the allocation of the purchase as follows:

Net assets acquired and liabilities assumed		
Property, plant and equipment	$	426,817
Working capital, net of cash acquired		38,937
Intangible asset - contracts and customer relationships		183,100
Intangible asset - fractionation spread support agreement		17,600
Intangible assets - other		16,308
Goodwill		100,409
Financial derivative instruments		945
Asset retirement obligation		(7,604)
Future income taxes		(3,173)
	$	773,339
Consideration		
Acquisition costs	$	12,179
Cash, net of cash acquired		761,160
	$	773,339

The Midstream NGL Acquisition was financed by the issue of 21,830,000 units at $12.60 per unit and $150 million of 6.5 percent convertible unsecured subordinated debentures. The remaining portion of the purchase price of the Midstream NGL Acquisition was funded through Provident's credit facility.

In February 2006, Provident sold its 49 percent interest in the Marysville Partnership, which owns the Marysville Underground Storage Terminal (MUST), for net cash proceeds of $11.5 million. The partnership interest was part of the assets acquired in the Midstream NGL acquisition. The purchase price allocation of the Midstream NGL acquisition was adjusted to reflect the revised fair value of the acquisition, resulting in an increase to goodwill amounting to $2.0 million.

In June 2006, Provident settled the final post-closing adjustments relating to the acquisition. The net cash payment resulted in an increase to goodwill amounting to $2.3 million.

In December 2006, Provident adjusted its estimate of acquisition costs relating to the acquisition. The purchase price allocation was adjusted to reflect the revised fair value of the acquisition, resulting in a decrease in goodwill of $2.0 million.

4. Sale of assets

On May 1, 2005, certain oil purchase and sale contracts were sold for net proceeds of $5.5 million and a gain of $5.2 million was recorded net of disposal costs.

On December 29, 2005, a parcel of land in California was sold for net proceeds of $23.8 million. The sale represents surface rights for real estate development, with no impact on oil and gas reserves. The transaction resulted in a deferred gain of $1.0 million. The purchaser has agreed to complete the removal and relocation of oilfield infrastructure and environmental remediation work. Not included in the net proceeds or deferred gain are contingent proceeds, amounting to $2.7 million, which are held in escrow until this work is completed.

5. Property, plant and equipment

December 31, 2006		**Cost**		**Accumulated depletion and depreciation**		**Net Book value**
Oil and natural gas properties	$	2,513,031	$	927,087	$	1,585,944
Midstream assets		781,092		42,143		738,949
Office equipment		17,070		8,426		8,644
Total	$	3,311,193	$	977,656	$	2,333,537

December 31, 2005		Cost		Accumulated depletion and depreciation		Net Book value
Oil and natural gas properties	$	1,710,998	$	731,336	$	979,662
Midstream assets		738,835		21,951		716,884
Office equipment		12,423		6,280		6,143
Total	$	2,462,256	$	759,567	$	1,702,689

Costs associated with unproved properties excluded from costs subject to depletion as at December 31, 2006 totaled $17.8 million (December 31, 2005 - $23.8 million). Asset retirement costs of $49.9 million are included in property, plant and equipment (December 31, 2005 - $38.6 million). Midstream assets include $22.0 million (2005 - $29.3 million) for products required for line-fill and cavern bottoms.

An impairment test calculation was performed on property, plant and equipment at December 31, 2006 in which the estimated undiscounted future net cash flows based on estimated future prices associated with the proved reserves exceeded the carrying amount of oil and gas property, plant and equipment for each cost centre.

The following table outlines prices used in the impairment test at December 31, 2006:

Year		**Oil $/bbl**		**Gas $/mcf**		**NGL $/bbl**
2007	$	50.87	$	7.00	$	51.66
2008	$	50.97	$	7.57	$	52.14
2009	$	50.18	$	7.81	$	50.85
2010	$	51.23	$	7.79	$	50.26
2011	$	51.00	$	7.78	$	49.74
Thereafter [(1)]		2.00%		2.00%		2.00%

[(1)] Percentage change represents the increase in each year after 2011 to the end of the reserve life.

6. Intangible assets

December 31, 2006		Cost		Accumulated amortization		Net Book value
Midstream and marketing contracts and customer relationships	$	183,100	$	12,842	$	170,258
Fractionation spread support arrangement		17,600		9,258		8,342
Other intangible assets		16,308		1,316		14,992
Total	$	217,008	$	23,416	$	193,592

December 31, 2005		Cost		Accumulated amortization		Net Book value
Midstream and marketing contracts and customer relationships	$	183,100	$	635	$	182,465
Fractionation spread support arrangement		17,600	$	458		17,142
Other intangible assets		16,308	$	65		16,243
Total	$	217,008	$	1,158	$	215,850

7. Long-term debt

		December 31, 2006		December 31, 2005
Revolving term credit facilities	$	702,993	$	586,597
Convertible debentures		285,792		298,007
	$	988,785	$	884,604

(i) **Revolving term credit facilities**

Provident has a $925 million term credit facility with a syndicate of Canadian chartered banks secured by midstream assets and by its Canadian oil and gas properties. Provident may draw on the credit facility by way of Canadian prime rate loans, U.S. base rate loans, banker's acceptances, letters of credit or LIBOR loans. At December 31, 2005 the facility totaled $750 million. In July 2006 the facility was increased to its current level of $925 million. At December 31, 2006, $691.9 million was drawn on this facility.

The terms of the credit facility have a revolving three year period expiring on May 30, 2009. Provident can extend the revolving period by an additional year, no earlier than 90 days and no later than 30 days prior to the end of the first year of the applicable three year revolving period. If the lenders do not extend the revolving period, or Provident chooses not to extend, the credit facility will be terminated and the loan balance will become due and payable in full on the maturity date.

In addition, Provident's U.S. subsidiaries have credit facilities with a borrowing base of U.S. $158 million with a syndicate of U.S. banks secured by oil and gas assets of the subsidiaries. Provident may draw upon the facility by way of U.S. base rate loans, LIBOR loans or letters of credit. The facilities have a termination date of October 10, 2010 and the current borrowing base is reviewed every six month period. At December 31, 2006, $11.1 million was drawn on these facilities.

At December 31, 2006 the effective interest rate of the outstanding credit facilities was 5.2 percent (2005 – 4.6 percent). At December 31, 2006 Provident had $31.9 million in letters of credit outstanding (2005 - $45.1 million) that guarantee Provident's performance under certain commercial and other contracts.

(ii) **Convertible debentures**

On November 15, 2005 the Trust issued $150.0 million of unsecured convertible subordinated debentures ($143.8 million net of issue costs) with a 6.5 percent coupon rate maturing April 30, 2011. Issue costs have been classified as deferred financing charges. The debentures may be converted into trust units at the option of the holder at a conversion price of $14.75 per trust unit prior to April 30, 2011 and may be redeemed by the Trust under certain circumstances. The unsecured subordinated convertible debentures were initially recorded at fair value of $141.4 million. The difference between the fair value and proceeds of $8.6 million was recorded as equity.

On May 31, 2005 the Trust completed the redemption of its 10.5 percent convertible unsecured subordinated debentures that were originally scheduled to mature May 15, 2007. A total of 3.5 million units were issued at the conversion price of $10.70 per unit. A further $3.0 million cash was paid to the remaining debenture holders that did not convert to trust units at $1,050 for each $1,000 of convertible debenture held plus accrued interest to May 31, 2005 resulting in a loss on redemption of $49,000. Unamortized deferred debt issue costs of $2.5 million, originally incurred on the issue of the 10.5 percent convertible debentures, were reclassified to trust unit issue costs as a result of the issue of 3.5 million trust units.

On March 1, 2005 the Trust issued $100.0 million of unsecured convertible subordinated debentures ($95.8 million net of issue costs) with a 6.5 percent coupon rate maturing August 31, 2012. Issue costs have been classified as deferred financing charges. The debentures may be converted into trust units at the option of the holder at a conversion price of $13.75 per trust unit prior to August 31, 2012 and may be redeemed by the Trust under certain circumstances. The unsecured subordinated convertible debentures were initially recorded at fair value of $92.6 million. The difference between the fair value and proceeds of $7.4 million was recorded as equity.

The Trust may elect to satisfy interest and principal obligations by the issue of trust units. For the twelve months ended December 31, 2006, $15.4 million of the face value of debentures were converted to trust units at the election of debenture holders (2005 - $109.3 million, including $45.7 million associated with the May 31, 2005 redemption of the 10.5 percent convertible unsecured subordinated debentures). The following table details each outstanding convertible debenture.

Convertible Debentures	**December 31, 2006**		December 31, 2005			
($ 000s except conversion pricing)	Carrying Value [1]	Face Value	Carrying Value [1]	Face Value	Maturity Date	Conversion Price per unit [2]
6.5% Convertible Debentures	$ **142,860**	$ **150,000**	$ 141,522	$ 150,000	April 30, 2011	14.75
6.5% Convertible Debentures	**93,134**	**99,024**	92,482	99,179	Aug. 31, 2012	13.75
8.0% Convertible Debentures	**24,402**	**25,114**	32,382	33,648	July 31, 2009	12.00
8.75% Convertible Debentures	**25,396**	**25,972**	31,621	32,659	Dec. 31, 2008	11.05
	$ **285,792**	$ **300,110**	$ 298,007	$ 315,486		

(1) Excluding equity component of convertible debentures.

(2) The debentures may be converted into trust units at the option of the holder of the debenture at the conversion price per unit.

8. Revenue

	Year ended December 31,	
	2006	2005
Gross production revenue	$ **578,255**	$ 621,761
Product sales and service revenue	**1,764,392**	908,111
Royalties	**(98,540)**	(110,422)
Revenue	**2,244,107**	1,419,450
Realized loss on financial derivative instruments	**(13,540)**	(66,860)
Unrealized (loss) gain on financial derivative instruments	**(43,314)**	7,684
	$ **2,187,253**	$ 1,360,274
Change in unrealized loss on financial derivative instruments	$ **(43,314)**	$ 9,828
Amortization of loss on financial derivative instruments	-	(2,144)
Unrealized (loss) gain on financial derivative instruments	$ **(43,314)**	$ 7,684

The realized loss on financial derivative instruments for the year ended December 31, 2006 of $13.5 million (2005 - $66.9 million) relates to the cash settlement on derivative instruments.

9. Asset retirement obligation

The Trust's asset retirement obligation is based on the Trust's net ownership in wells, facilities and the midstream assets and represents management's estimate of the costs to abandon and reclaim those wells, facilities and midstream assets as well as an estimate of the future timing of the costs to be incurred. Estimated cash flows have been discounted at the Trust's credit-adjusted risk free rate of seven percent and an inflation rate of two percent has been estimated for future years.

The total undiscounted amount of future cash flows required to settle asset retirement obligations related to oil and gas operations is estimated to be $411.6 million (2005 - $293.0 million). Payments to settle oil and gas asset retirement obligations occur over the operating lives of the assets estimated to be from three to 49 years.

The total undiscounted amount of future cash flows required to settle the midstream services and marketing asset retirement obligations is estimated to be $166.1 million (2005 - $179.3 million). The estimated costs include such activities as dismantling, demolition and disposal of the facilities as well as remediation and restoration of the surface land. Payments to settle the midstream services and marketing asset retirement obligations are expected to occur subsequent to the closure of the facilities and related assets. Settlement of these obligations is expected to occur in 30 to 45 years.

	Year ended December 31,			
		2006		2005
Carrying amount, beginning of year	**$**	**41,133**	$	40,506
Acquisitions		**1,903**		9,161
Change in estimate		**6,793**		2,884
Increase in liabilities incurred during the period		**1,443**		1,784
Settlement of liabilities during the period		**(4,622)**		(2,614)
Decrease in liabilities due to disposition		**(946)**		(13,612)
Accretion of liability		**3,910**		3,024
Carrying amount, end of year	**$**	**49,614**	$	41,133

10. Non-controlling interests

(i) USOGP operations

Year ended December 31,		**2006**		2005
Non-controlling interest, beginning of year	$	**11,885**	**$**	13,649
Net income attributable to non-controlling interest		**2,995**		1,596
Distributions to non-controlling interest holders		**(6,523)**		(3,360)
Investments by non-controlling interest		**72,754**		-
Non-controlling interest, end of year	$	**81,111**	**$**	11,885
Accumulated income attributable to non-controlling interest	$	**5,514**	**$**	2,519

A non-controlling interest arose from Provident's June 15, 2004 acquisition of 92 percent of BreitBurn Energy Company L.P. (BreitBurn) of Los Angeles, California. Additional investments since June 2004 by Provident in BreitBurn have reduced the non-controlling interest percentage at December 31, 2006 to approximately 4.4 percent (2005 – 4.4 percent). Contributions by this non-controlling interest total $0.5 million in 2006 (2005 – nil).

In the second quarter of 2006, a USOGP subsidiary began a land development project with a partner. The subsidiary has a 20 percent interest, with the partner holding 80 percent. Because the subsidiary stands to receive a majority share of the future proceeds, Provident is consolidating the results in its statements, with non-controlling interest. Contributions by the non-controlling interest total $3.7 million in 2006.

In the fourth quarter of 2006, Provident's subsidiary, BreitBurn Energy Partners, L.P. (the "MLP") completed its initial public offering. BreitBurn transferred oil and gas properties comprising approximately half of its proved reserves and two thirds of its daily production to the MLP. The

offering, including an underwriter's option, of 6,900,000 common units at U.S. $18.50 per unit, resulted in approximately 34 percent of the MLP held by partners not controlled by Provident. Contributions by this non-controlling interest total $131.6 million in 2006. Non-controlling interest was increased by $68.5 million as a result of this transaction. The difference of $63.1 million has been recorded against property, plant and equipment in accordance with full cost accounting principles.

(ii) **Exchangeable shares**

The non-controlling interest on the consolidated balance sheet consists of the fair value of the exchangeable shares upon issue plus the accumulated earnings attributable to the non-controlling interest. The net income attributable to the non-controlling interest on the consolidated statement of operations represents the cumulative share of net income attributable to the non-controlling interest based on the trust units issuable for exchangeable shares in proportion to total trust units issued and issuable at each quarter end during the year. In 2006, all outstanding exchangeable shares were converted into Provident trust units.

Following is a summary of the non-controlling interest – exchangeable shares for years ended December 31, 2006 and 2005:

Year ended December 31,		**2006**		2005
Non-controlling interest, beginning of year	$	**8,259**	**$**	35,921
Reduction of book value for conversion to trust units		**(9,013)**		(28,432)
Net income attributable to non-controlling interest		**754**		770
Non-controlling interest, end of year	$	-	**$**	8,259
Accumulated income attributable to non-controlling interest	$	-	**$**	2,252

The following table details the number of exchangeable shares converted and outstanding in addition to the associated book value:

	Year ended December 31,					
	2006			2005		
Exchangeable shares Provident Acquisitions Inc.	**Number of units**		**Amount**	Number of units		Amount
Balance at beginning of year	-	$	-	336,876	$	3,675
Converted to trust units	-		-	(336,876)		(3,675)
Balance, end of year	-		-	-		-
Exchange ratio, end of year	-			-		
Trust units issuable upon conversion, end of year	-	$	-	-	$	-
Exchangeable shares Provident Energy Ltd.						
Balance at beginning of year	**463,545**	**$**	**4,961**	638,474	$	6,833
Converted to trust units	**(463,545)**		**(4,961)**	(174,929)		(1,872)
Balance, end of year	-		-	463,545		4,961
Exchange ratio, end of year	-			1.50962		
Trust units issuable upon conversion, end of year	-	$	-	699,777	$	4,961
Exchangeable shares (Series B) Provident Energy Ltd.						
Balance at beginning of year	**91,320**	**$**	**1,046**	2,095,271	$	23,931
Converted to trust units	**(91,320)**		**(1,046)**	(2,003,951)		(22,885)
Balance, end of year	-		-	91,320		1,046
Exchange ratio, end of year	-			1.19311		
Trust units issuable upon conversion, end of year	-	$	-	108,955	$	1,046
Total Trust units issuable upon conversion of all exchangeable shares, end of year	-	$	-	808,732	$	6,007

11. Unitholders' contributions

The Trust has authorized capital of an unlimited number of common voting trust units.

Trust units are redeemable at any time on demand by the holders thereof. Upon receipt of a redemption request by the Trust, the holder is entitled to receive a price per trust unit (the "Market Redemption Price") equal to the lesser of: (i) 90% of the simple average of the closing price of the trust units on the principal market on which the trust units are quoted for trading during the 10 trading day period commencing immediately after the date on which the trust units are surrendered for redemption; and (ii) the closing market price on the principal market on which the trust units are quoted for trading on the date that the trust units are surrendered for redemption.

The aggregate Market Redemption Price payable by the Trust in respect of any trust units surrendered for redemption during any calendar month shall be satisfied by way of a cash payment on the last day of the following month. Total cash payments for redemption are limited to an annual maximum of $250,000. Any excess over the maximum may be satisfied by distributing notes having an aggregate principal amount equal to the aggregate Market Redemption Price of the trust units tendered for redemption.

(i) **2006 activity**

On July 31, 2006 the Trust issued 16,325,000 Subscription Receipts at a price of $13.85 per Subscription Receipt for total proceeds of $226.1 million ($214.2 million net of issue costs). Each Subscription Receipt entitled the holder to receive one trust unit upon completion of the Rainbow asset acquisition. The acquisition closed on August 31, 2006 at which time all the outstanding Subscription Receipts were converted into trust units. At that time, the holders of the Subscription Receipts were also entitled to $0.12 per trust unit, which is the equivalent of the August distribution paid in September. This payment was treated as a reduction to the proceeds received for the units issued through the Subscription Receipts to $13.73 per trust unit, reducing the amount attributed to Unitholders' contributions by $2.0 million. Proceeds from the issue were used to fund the Rainbow asset acquisition.

In 2006 the Trust issued 6.1 million units related to Provident's DRIP program, conversion of exchangeable shares to units, conversion of convertible debentures to units and units issued pursuant to Provident's Unit Option Plan. The net increase in unitholders' contributions associated with these activities was $70.1 million.

(ii) **2005 activity**

On March 1, 2005 the Trust issued 8.4 million units at $12.00 per unit for proceeds of $100.8 million ($95.6 million net of issue costs) pursuant to a February 18, 2005 public offering.

On November 15, 2005 the Trust issued 21.83 million Subscription Receipts at a price of $12.60 per Subscription Receipt for total proceeds of $275.1 million ($261.0 million net of issue costs). Each Subscription Receipt entitled the holder to receive one trust unit upon completion of the Midstream NGL Acquisition. The acquisition closed on December 13, 2005 at which time all of the outstanding Subscription Receipts were converted to trust units. At that time, the holders of the Subscription Receipts were also entitled to $0.12 per trust unit, which is the equivalent of the November distribution paid in December. This payment was treated as a reduction to the proceeds received for the units issued through the Subscription Receipts to $12.48 per trust unit, reducing the amount attributed to Unitholders' contributions by $2.6 million. Proceeds from the issue were used to fund the Midstream NGL Acquisition.

In 2005 the Trust issued 16.3 million units related to Provident's DRIP program, conversion of exchangeable shares to units, conversion and redemption of convertible debentures to units and units issued pursuant to Provident's Unit Option Plan. The net increase in unitholders' contributions associated with these activities was $181.8 million.

	Year ended December 31,			
	2006		2005	
Trust Units	**Number of units**	**Amount (000s)**	Number of units	Amount (000s)
Balance at beginning of year	**188,772,788**	**$ 1,971,707**	142,226,248	$ 1,438,393
Issued for cash	**16,325,000**	**224,142**	30,230,000	373,238
Exchangeable share conversions	**881,083**	**9,012**	2,971,217	28,432
Issued pursuant to unit option plan	**907,201**	**8,589**	2,265,179	23,435
Issued pursuant to the distribution reinvestment plan	**2,714,636**	**33,045**	1,330,156	16,438
To be issued pursuant to the distribution reinvestment plan	**300,134**	**3,806**	107,000	2,005
Debenture conversions	**1,327,565**	**15,689**	6,135,418	64,808
Redemption of the 10.5% debentures (note 7)	-	-	3,507,570	46,707
Unit issue costs	-	**(11,942)**	-	(21,749)
Balance at end of year	211,228,407	$ 2,254,048	188,772,788	$ 1,971,707

The basic per trust unit amounts for 2006 were calculated based on the weighted average number of units outstanding of 196,627,060 (2005 – 159,315,847). The diluted per trust unit amounts for 2006 are calculated including an additional 286,957 trust units (2005 – 369,566) for the effect of the unit option plan. Provident's convertible debentures are not included in the computation of diluted earnings per unit as their effect is anti-dilutive.

12. Unit based compensation

(i) **Restricted/Performance units**

Certain employees of the Trust's Canadian subsidiaries are granted restricted trust units (RTUs) and/or performance trust units (PTUs), both of which entitle the employee to receive cash compensation in relation to the value of a specific number of underlying notional trust units. The grants are based on criteria designed to recognize the long term value of the employee to the organization. RTUs vest evenly over a period of three years commencing at the grant date. Payments are made on the anniversary dates of the RTU to the employees entitled to receive them on the basis of a cash payment equal to the value of the underlying notional units. PTUs vest three years from the date of grant and can be increased to a maximum of double the PTUs granted or a minimum of nil PTUs depending on the Trust's performance vis-à-vis other trusts' performance based on certain benchmarks.

As of December 31, 2006 there were 571,423 RTUs and 1,704,234 PTUs outstanding (2005 – 226,055 RTUs and 464,291 PTUs). The fair value estimate associated with the RTUs and PTUs is expensed in the statement of operations over the vesting period. At December 31, 2006, $2.3 million (2005 - $1.0 million) is included in accounts payable and accrued liabilities for this plan and $13.3 million (2005 - $2.5 million) is included in other long-term liabilities. The following table reconciles the expense recorded for RTUs and PTUs.

Year ended December 31,	**2006**	2005
Cash general and administrative	$ **1,021**	$ -
Non-cash unit based compensation (included in general and administrative)	**11,156**	2,600
Operating expense	**939**	-
	$ **13,116**	$ 2,600

(ii) **Unit option plan**

The Trust option plan (the "Plan") is administered by the Board of Directors of Provident. Under the Plan, all directors, officers and employees of Provident were eligible to participate in the Plan. There are 8,000,000 trust units reserved for the Trust option plan. Options were granted at a "strike price" which is not less than the closing price of the units on the Toronto Stock Exchange on the last trading day preceding the grant. In certain circumstances, based upon the cash distributions made on the trust units, the strike price may be reduced at the time of exercise of the option at the discretion of the option holder. Options vest six months after grant and every year thereafter in equal increments. In October 2005, a restricted/performance unit program (see (i)) was approved. This program replaces the unit option plan. Unit options in existence will continue to be outstanding.

Year ended December 31,	2006		2005	
	Number of Options	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price
Outstanding, beginning of year	**3,205,625**	**$11.11**	5,200,331	$11.01
Granted	-	-	296,200	11.73
Exercised	**(907,201)**	**11.13**	(2,265,179)	10.97
Forfeited	**(183,616)**	**11.08**	(25,727)	10.97
Outstanding, end of year	**2,114,808**	**$11.09**	3,205,625	$11.11
Exercisable, end of year	**1,947,989**	**$11.08**	2,206,801	$11.12

At December 31, 2006, the Trust had 2,114,808 options outstanding with strike prices ranging between $10.49 and $12.14 per unit. The weighted average remaining contractual life of the options is 1.96 years and the weighted average exercise price is $11.09 per unit excluding average potential reductions to the strike prices of $1.50 per unit.

At December 31, 2005, the Trust had 3,205,625 options outstanding with strike prices ranging from $8.91 and $12.14 per unit. The weighted average remaining contractual life of the options was 2.20 years and the weighted average exercise price was $11.11 per unit excluding average potential reductions to the strike prices of $1.16 per unit.

In 2006 the Trust recorded non-cash unit based compensation expense of $0.2 million, for the 5.6 million options granted on or after January 1, 2003 (2005 - $1.1 million).

As at December 31, 2006, the following assumptions are the weighted averages of the individual assumptions applied at each grant date to arrive at an estimate of fair value of all granted options on or after January 1, 2003 of $3.8 million:

	2005 Granted Options	2004 Granted Options	2003 Granted Options
Expected annual dividend	8.00%	8.00%	8.00%
Expected volatility	19.88%	20.18%	19.46%
Risk - free interest rate	3.26%	3.30%	3.66%
Expected life of option (yrs)	3.31	3.31	3.31
Expected forfeitures	-	-	-
Fair Value of Granted Options	$0.2 million	$1.2 million	$2.4 million

The remaining fair value of the rights of $0.1 million, less any future cancellations, will be recognized in earnings over the remaining vesting period of the rights outstanding. The following table reconciles the movement in the contributed surplus balance.

Year ended December 31,		**2006**		2005
Contributed surplus, beginning of the year	$	**1,675**	$	2,002
Non-cash unit based compensation (included in general and administrative)		**203**		1,055
Benefit on options exercised charged to unitholders' equity		**(563)**		(1,382)
Contributed surplus, end of year	$	**1,315**	$	1,675

(iii) **Unit appreciation rights**

Certain employees of the Trust's U.S. subsidiaries are granted unit appreciation rights (UARs) which entitle the employee to receive cash compensation in relation to the value of a specific number of underlying notional trust units. UARs vest evenly over a period of three years commencing one year after grant and expire after four years.

The UARs upon vesting, provide certain employees entitlement to receive a cash payment equal to the excess of the market price of the Trust's units over the exercise price of the right less notionally accrued distributions in excess of an eight percent return. These prices are denominated in U.S. dollars and are based on quoted U.S. distributions and market prices.

The fair value associated with the UARs is expensed in the statement of operations over the vesting period. At December 31, 2006, $2.5 million (2005 - $0.7 million) is included in accounts payable and accrued liabilities for this plan and $0.1 million (2005 - $0.7 million) is included in other long-term liabilities. The following table reconciles the expense recorded for UARs.

Year ended December 31,		2006		2005
Cash general and administrative	$	798	$	1,034
Non-cash unit based compensation (included in general and administrative)		1,246		1,137
	$	2,044	$	2,171

The following table summarizes the information about UARs:

	2006			2005		
Year ended December 31,	Number of Unit Appreciation Rights		Weighted Average Exercise Price (U.S.$)	Number of Unit Appreciation Rights		Weighted Average Exercise Price (U.S.$)
Outstanding, beginning of year	768,693	$	8.34	976,000	$	7.98
Granted	-		-	147,000		10.01
Exercised	(282,840)		8.20	(296,641)		7.91
Forfeited	(13,332)		8.85	(57,666)		8.79
Outstanding, end of year	472,521	$	8.41	768,693	$	8.34
Exerciseable, end of year	81,852	$	8.46	22,704	$	8.92
Weighted average remaining contract life (years)	1.58			2.58		
Average potential reductions to exercise price	$1.30			$0.71		

(iv) **Other unit based compensation**

Pursuant to employment agreements between the Trust's U.S. subsidiaries and certain employees, the employees are eligible to receive cash compensation in relation to the value of a specified number of underlying notional units. The value of each notional unit is determined on the basis of a valuation of the U.S. subsidiaries as at the end of the fiscal period. At December 31, 2006 there were 2,755,566 notional units outstanding under the key employee plan (2005 – 2,200,000) which vest one third three years after grant date, one third four years after grant date and one third five years after grant date. In 2006, 555,566 units were granted with the remaining 2,200,000 being granted in 2004. There were 12,984,001 notional units outstanding under the phantom unit plan (2005 – 4,155,290) of which all notional units vest immediately and are payable 90 days from the fiscal year-end. At December 31, 2006, $13.4 million (2005 - $3.5 million) is included in accounts payable and accrued liabilities for these plans, and $2.9 million (2005 - $1.8 million) is included in other long-term liabilities.

The following table reconciles the expense recorded for the other unit based compensation plans.

Year ended December 31,		2006		2005
Cash general and administrative	$	3,807	$	1,255
Non-cash unit based compensation (included in general and administrative)		10,478		4,961
	$	14,285	$	6,216

13. Income taxes

Provident follows the liability method for calculating future income taxes. Under this method, future income tax assets and liabilities are recognized based on the estimated tax effects of temporary differences in the carrying value of assets and liabilities, reported in the financial statements of the corporate subsidiaries, and their respective tax bases, using income tax rates substantively enacted on the consolidated balance sheet date:

		Year ended December 31,		
		2006		2005
Petroleum and natural gas properties, production facilities and other	$	**266,156**	$	89,607
Midstream facilities		**42,850**		1,988
	$	**309,006**	$	91,595

The income tax provision differs from the expected amount calculated by applying the Canadian combined federal and provincial income tax rate of 34.67 percent (2005 – 37.82 percent) as follows:

		Year ended December 31,		
		2006		2005
Expected income tax expense	$	**40,736**	$	48,218
Increase (decrease) resulting from:				
Non-deductible Crown charges and other payments		**8,135**		14,285
Federal resource allowance		**(5,742)**		(11,489)
Alberta Royalty Tax Credit		**(173)**		(188)
Income of the Trust and other		**(70,999)**		(32,567)
Capital Taxes		**1,314**		4,780
Witholding tax and other		**3,308**		5,628
Income tax rate changes		**(3,752)**		(466)
Income tax (recovery) expense	$	**(27,173)**	$	28,201

On December 21, 2006, the Minister of Finance released for comment draft legislation concerning the taxation of certain publicly traded trusts and partnerships. The legislation reflects proposals originally announced by the Minister on October 31, 2006. Under the proposed legislation, certain distributions will not be deductible to publicly traded income trusts and partnerships with the exception of real estate investments trusts and, as a result, these entities will in effect be taxed as corporations on the amount of the non-deductible distributions. For entities in existence on October 31, 2006 the proposed rules, if passed into law, would not apply until 2011. As the tax proposals had not been substantially enacted as of December 31, 2006, the consolidated financial statements do not reflect the impact of the proposed taxation.

14. Financial instruments and hedging

Financial instruments of the Trust carried on the consolidated balance sheet consist mainly of cash and cash equivalents, accounts receivable, reclamation fund investments, current liabilities, asset retirement obligations, commodity and foreign currency contracts and long-term debt. Except as noted below, as at December 31, 2006 and 2005, there were no significant differences between the carrying value of these financial instruments and their estimated fair value.

Substantially all of the Trust's accounts receivable are due from customers and joint venture partners in the oil and gas and midstream services and marketing industries and are subject to credit risk. The Trust partially mitigates associated credit risk by limiting transactions with certain counterparties to limits imposed by the Trust based on the Trust's assessment of the creditworthiness of such counterparties. The carrying value of accounts receivable reflects management's assessment of the associated credit risks. With respect to counterparties to financial instruments, the Trust partially mitigates associated credit risk by limiting transactions to counterparties with investment grade credit ratings and obtaining financial guarantees from certain counterparties.

Provident's commodity price risk management program is intended to minimize the volatility of commodity prices and to assist with stabilizing cash flow and distributions. Provident seeks to accomplish this through the use of financial instruments from time to time to reduce its exposure to fluctuations in commodity prices and foreign exchange rates.

With respect to financial instruments, Provident could be exposed to losses if a counterparty fails to perform in accordance with the terms of the contract. This risk is managed by diversifying the derivative portfolio among counterparties meeting certain financial criteria.

(i) **Commodity price**

a) **Crude oil**

In 2006, Provident paid $5.7 million to settle various oil market based contracts on an aggregate volume of 2.1 million barrels. For 2005, Provident paid $59.0 million to settle various oil market based contracts on an aggregate volume of 2.6 million barrels. The estimated value of contracts in place if settled at market prices at December 31, 2006 would have resulted in an opportunity gain of $7.2 million (2005 – an opportunity cost of $7.1 million).

b) **Natural Gas**

In 2006, Provident received $7.6 million to settle various natural gas market based contracts on an aggregate of 9.5 million gigajoules ("GJ"). For 2005, Provident paid $5.6 million to settle various natural gas market based contracts on an aggregate of 5.2 million gigajoules ("GJ"). The estimated value of contracts in place if settled at market prices at December 31, 2006 would have resulted in an opportunity gain of $8.6 million (2005 – an opportunity cost of $6.5 million).

c) **Midstream**

In 2006, Provident paid $15.4 million (2005 - $2.3 million) to settle various midstream contracts, that were entered into to fix prices on product sales. The estimated value of contracts in place if settled at market prices as December 31, 2006 would have resulted in an opportunity cost of $68.8 million (2005 – $0.4 million).

(ii) **Foreign exchange contracts**

The estimated value of contracts in place if settled at foreign exchange rates at December 31, 2006 would have resulted in an opportunity gain of $0.1 million (2005 – opportunity cost of $0.1 million). The foreign exchange gains have been included in note 17 as a component of foreign exchange gain and other and allocated to their respective business segments.

The contracts in place at December 31, 2006 are summarized in the following tables:

COGP

Year	Product	Volume (Buy)Sell	Terms	Effective Period
2007	**Crude Oil**	750 Bpd	Participating Swap US $60.00 per bbl (62% above the floor price)	January 1 - December 31
		750 Bpd	Puts US $60.00 per bbl	January 1 - December 31
	Natural Gas	2,500 Gjpd	Participating Swap Cdn $6.50 per gj (65% above the floor price)	January 1 - August 31
		2,000 Gjpd	Participating Swap Cdn $6.50 per gj (max to 100% above the floor price)	January 1 - August 31
		5,000 Gjpd	Participating Swap Cdn $7.00 per gj (max to 82% above the floor price)	January 1 - March 31
		1,500 Gjpd	Participating Swap Cdn $7.00 per gj (max to 80% above the floor price)	January 1 - March 31, November 1 - December 31
		4,000 Gjpd	Participating Swap Cdn $6.44 per gj (max to 100% above the floor price)	April 1 - August 31
		1,500 Gjpd	Participating Swap Cdn $6.50 per gj (max to 61% above the floor price)	April 1 - August 31
		3,000 Gjpd	Participating Swap Cdn $6.33 per gj (max to 100% above the floor price)	April 1 - October 31
		3,000 Gjpd	Participating Swap Cdn $6.33 per gj (max to 90% above the floor price)	April 1 - October 31
		6,000 Gjpd	Participating Swap Cdn $6.30 per gj (max to 95% above the floor price)	April 1 - October 31
		2,000 Gjpd	Participating Swap Cdn $6.13 per gj (max to 68% above the floor price)	April 1 - October 31
		1,000 Gjpd	Participating Swap Cdn $6.00 per gj (max to 66% above the floor price)	April 1 - October 31
		6,500 Gjpd	Costless Collar Cdn $6.31 floor, Cdn $12.93 ceiling	January 1 - March 31
		7,500 Gjpd	Costless Collar Cdn $6.42 floor, Cdn $9.63 ceiling	January 1 - August 31
		4,000 Gjpd	Costless Collar Cdn $6.75 floor, Cdn $8.56 ceiling	April 1 - August 31
		5,000 Gjpd	Puts Cdn $6.85 per gj	January 1 - December 31
		2,000 Gjpd	Puts Cdn $6.75 per gj	January 1 - March 31
		9,500 Gjpd	Puts Cdn $6.89 per gj	January 1 - March 31, November 1 - December 31
		4,000 Gjpd	Puts Cdn $6.75 per gj	November 1 - December 31

USOGP

Year	Product	Volume (Buy)Sell	Terms	Effective Period
2007	Crude Oil	250 Bpd	US $60.00 per bbl	January 1 - December 31
		250 Bpd	Participating Swap US $55.00 per bbl (max to 84% above the floor price)	January 1 - December 31
		3,500 Bpd	US $67.84 per bbl	January 1 - June 30
		2,650 Bpd	US $68.44 per bbl	July 1 - December 31
		250 Bpd	Costless Collar US $66.00 floor, US $69.25 ceiling	July 1 - December 31
		250 Bpd	Costless Collar US $66.00 floor, US $71.50 ceiling	July 1 - December 31
2008	Crude Oil	2,650 Bpd	US $68.44 per bbl	January 1 - June 30
		250 Bpd	Costless Collar US $66.00 floor, US $69.25 ceiling	January 1 - June 30
		250 Bpd	Costless Collar US $66.00 floor, US $71.50 ceiling	January 1 - June 30
		2,500 Bpd	Participating Swap US $60.00 per bbl (max to 53.3% above the floor price)	July 1 - September 31
		4,500 Bpd	Participating Swap US $60.00 per bbl (avg to 56% above the floor price)	October 1 - December 31
2009	Crude Oil	500 Bpd	Participating Swap US $60.00 per bbl (max to 55.5% above the floor price)	January 1 - September 30
		2,000 Bpd	Participating Swap US $60.00 per bbl (max to 59% above the floor price)	January 1 - September 30

Midstream

Year	Product	Volume (Buy)Sell	Terms	Effective Period
2007	Crude Oil	250 Bpd	Costless Collar US $64.50 floor, US $69.20 ceiling	January 1 - December 31
		2,000 Bpd	Costless Collar US $72.43 floor, US $80.29 ceiling	April 1 - December 31
		10,077 Bpd	Cdn $77.02 per bbl	January 1 - December 31
		(7,643) Bpd	Cdn $64.35 per bbl [4]	January 1 - March 31
		(1,122) Bpd	US $80.81 per bbl [4]	January 1 - March 31
	Natural Gas	3,000 Gjpd	Cdn $8.28 per gj	January 1 - January 31
		(1,350) Gjpd	Costless Collar Cdn $8.62 floor, Cdn $9.10 ceiling	January 1 - December 31
		(3,201) Gjpd	Cdn $7.70 per gj	January 1 - March 31
		(22,196) Gjpd	Cdn $8.17 per gj	April 1 - December 31
		(48,493) Gjpd	Cdn $8.20 per gj	January 1 - December 31
	Propane	9,328 Bpd	US $0.9841 per gallon [4] [6]	January 1 - March 31
		806 Bpd	US $0.965 per gallon [6] [8]	January 1 - February 28
		1,666 Bpd	US $0.9668 per gallon [6] [8]	January 1 - March 31
		948 Bpd	Cdn $1.2081 per gallon [4] [6]	January 1 - March 31
	Normal Butane	1,808 Bpd	US $1.1135 per gallon [4] [7]	January 1 - March 31
		306 Bpd	Cdn $1.3788 per gallon [4] [7]	January 1 - March 31
	Foreign Exchange		Sell US $817,163 per month @ 1.1434 [5]	January 1 - December 31
			Sell US $968,486 per month @ 1.1013 [5]	April 1 - December 31
2008	Crude Oil	2,250 Bpd	Costless Collar US $68.50 floor, US $73.72 ceiling	January 1 - December 31
		500 Bpd	Costless Collar US $73.00 floor, US $80.00 ceiling	January 1 - June 30
		500 Bpd	Costless Collar US $64.00 floor, US $74.50 ceiling	January 1 - September 30
		250 Bpd	US $65.60 per bbl	January 1 - December 31
		8,521 Bpd	Cdn $76.65 per bbl	January 1 - December 31
	Natural Gas	(56,824) Gjpd	Cdn $8.34 per gj	January 1 - December 31
		(13,123) Gjpd	Cdn $8.60 per gj	January 1 - June 30
		(2,965) Gjpd	Cdn $7.94 per gj	January 1 - September 30
		(8,760) Gjpd	Cdn $7.94 per gj	July 1 - December 31
	Foreign Exchange		Sell US $599,652 per month @ 1.1172 [5]	January 1 - December 31
			Sell US $1,107,166 per month @ 1.1035 [5]	January 1 - June 30
			Sell US $974,222 per month @ 1.1255 [5]	January 1 - September 30
2009	Crude Oil	2,500 Bpd	Costless Collar US $65.00 floor, US $69.23 ceiling	January 1 - December 31
		500 Bpd	Costless Collar US $70.00 floor, US $79.00 ceiling	January 1 - June 30
		1,500 Bpd	Cdn $81.44 per bbl	January 1 - June 30
		250 Bpd	Cdn $77.37 per bbl	January 1 - March 31
		500 Bpd	Cdn $75.10 per bbl	July 1 - December 31
		250 Bpd	Cdn $76.70 per bbl	July 1 - September 30
		250 Bpd	US $64.60 per bbl	January 1 - December 31
		3,374 Bpd	Cdn $74.26 per bbl	January 1 - December 31
	Natural Gas	(35,261) Gjpd	Cdn $8.28 per gj	January 1 - December 31
		(1,481) Gjpd	Cdn $8.74 per gj	January 1 - March 31
		(14,714) Gjpd	Cdn $8.32 per gj	January 1 - June 30
		(1,481) Gjpd	Cdn $7.59 per gj	July 1 - September 30
		(2,776) Gjpd	Cdn $7.75 per gj	July 1 - December 31
	Foreign Exchange		Sell US $522,154 per month @ 1.1093 [5]	January 1 - December 31
			Sell US $1,055,833 per month @ 1.099 [5]	January 1 - June 30
2010	Crude Oil	1,500 Bpd	Costless Collar US $62.90 floor, US $67.48 ceiling	January 1 - December 31
		4,688 Bpd	Cdn $72.98 per bbl	January 1 - December 31
	Natural Gas	(35,273) Gjpd	Cdn $8.03 per gj	January 1 - December 31
		(1,485) Gjpd	Cdn $7.09 per gj	April 1 - December 31
	Foreign Exchange		Sell US $472,828 per month @ 1.1078 [5]	January 1 - December 31

Midstream, continued

Year	Product	Volume (Buy)Sell	Terms	Effective Period
2011	Crude Oil	500 Bpd	Costless Collar US $65.00 floor, US $75.00 ceiling	January 1 - June 30
		250 Bpd	Costless Collar US $60.00 floor, US $68.10 ceiling	July 1 - September 30
		250 Bpd	Costless Collar US $60.00 floor, US $67.30 ceiling	July 1 - September 30
		500 Bpd	Costless Collar US $56.00 floor, US $75.25 ceiling	July 1 - September 30
		500 Bpd	Costless Collar US $58.00 floor, US $76.20 ceiling	July 1 - September 30
		500 Bpd	Costless Collar US $60.00 floor, US $71.60 ceiling	July 1 - September 30
		3,250 Bpd	Cdn $74.26 per bbl	January 1 - June 30
		750 Bpd	Cdn $69.94 per bbl	January 1 - March 31
		885 Bpd	Cdn $70.99 per bbl	January 1 - September 30
		250 Bpd	Cdn $73.35 per bbl	January 1 - October 31
		250 Bpd	Cdn $72.75 per bbl	January 1 - November 30
		500 Bpd	Cdn $73.15 per bbl	April 1 - June 30
	Natural Gas	(2,700) Gjpd	Cdn $8.53 per gj	January 1 - March 31
		(23,726) Gjpd	Cdn $7.46 per gj	January 1 - June 30
		(4,955) Gjpd	Cdn $7.02 per gj	January 1 - September 30
		(1,481) Gjpd	Cdn $7.25 per gj	January 1 - October 31
		(1,481) Gjpd	Cdn $7.24 per gj	January 1 - November 30
		(11,859) Gjpd	Cdn $6.72 per gj	July 1 - September 30
		(2,820) Gjpd	Cdn $6.21 per gj	April 1 - June 30
	Foreign Exchange		Sell US $980,417 per month @ 1.0805 (5)	January 1 - June 30
			Sell US $717,600 per month @ 1.0931 (5)	July 1 - September 30

(1) The above table represents a number of transactions entered into over an extended period of time.
(2) Natural gas contracts are settle against AECO monthly index
(3) Crude Oil contracts are settled against NYMEX WTI calendar average
(4) Conversion of crude oil BTU hedges to propane
(5) U.S. Dollar hedge contracts settled against Bank of Canada noon rate average
(6) Propane contracts are settled against Belvieu C3 TET
(7) Normal butane contracts are settled against Belvieu NC4 NON-TET
(8) Midstream inventory hedges

15. Cash reserve for future site reclamation

Provident established a cash reserve effective May 1, 2001 for future site reclamation expenditures relating to its Canadian oil and gas production. In accordance with the royalty agreement, Provident funds the reserve by paying $0.30 per barrel of oil equivalent produced on a 6:1 basis into a segregated cash account. Actual expenditures incurred are then funded from the cash in this account. The cash reserve was $1.9 million at the beginning of 2006. For the year ended December 31, 2006, $2.7 million was contributed to the reserve and actual expenditures totaled $4.6 million. During 2006, Provident retired a number of wells that included non-routine costs. As a result, the cash reserve was depleted in the year. It is expected that the reserve will rebuild in 2007. For the year ended December 31, 2005, $2.9 million was added to the cash reserve and actual expenditures totaled $2.5 million.

16. Commitments

Provident has office lease commitments that extend through April 2013. Future minimum lease payments for the following five years are: 2007 - $4.6 million; 2008 - $8.0 million; 2009 - $7.8 million; 2010 - $6.9 million; and 2011 - $6.9 million.

In relation to the midstream services and marketing segment, Provident is committed to minimum lease payments under the terms of various rail tank car leases for the following five years: 2007 – U.S. $5.8 million; 2008 – U.S. $5.6 million; 2009 – U.S. $4.2 million; 2010 – U.S. $2.7 million; and 2011 – U.S. $1.5 million. Additionally, under an arrangement to use a third party interest in the Younger plant, Provident has a commitment to make payments calculated with reference to a number of variables including return on capital. Payments for the next five years are estimated as follows: 2007 – $4.5 million; 2008 - $4.3 million; 2009 - $4.0 million; 2010 - $3.8 million; and 2011 – 4.1 million.

In relation to the United States oil and natural gas production segment, Provident has surety bonds to provide U.S. $4.9 million of coverage to Occidental Petroleum Corporation related to a purchase of oil and gas producing properties.

In relation to the United States oil and natural gas production segment, Provident leases certain property and equipment under operating leases. Future minimum lease payments for the following five years are as follows: 2007 – U.S. $0.7 million; 2008 – U.S. $0.6 million; 2009 – U.S. $0.6 million; 2010 – U.S. $0.6 million; and 2011 – U.S. $0.6 million.

17. Segmented information

The Trust's business activities are conducted through three business segments: Canadian oil and natural gas production (COGP), United States oil and natural gas production (USOGP) and midstream services and marketing.

Oil and natural gas production in Canada and the United States includes exploitation, development and production of crude oil and natural gas reserves. Midstream services and marketing includes processing, extraction, transportation, loading and storage of natural gas liquids, and marketing of natural gas liquids.

Geographically the Trust operates in Canada and the USA in the oil and gas production business segment. The geographic components have been presented for the oil and natural gas business as well as the midstream services and marketing business that operates in both Canada and the USA.

	Year ended December 31, 2006				
	Canada Oil and Natural Gas Production	United States Oil and Natural Gas Production	Total Oil and Natural Gas Production	Midstream Services and Marketing [(1)]	Total
Revenue					
Gross production revenue	$ 402,095	$ 176,160	$ 578,255	$ -	$ 578,255
Royalties	(81,225)	(17,315)	(98,540)	-	(98,540)
Product sales and service revenue	-	-	-	1,764,392	1,764,392
Realized gain (loss) on financial derivative instruments	4,371	(2,505)	1,866	(15,406)	(13,540)
	325,241	156,340	481,581	1,748,986	2,230,567
Expenses					
Cost of goods sold	-	-	-	1,471,171	1,471,171
Production, operating and maintenance	97,626	52,008	149,634	22,619	172,253
Transportation	5,114	-	5,114	14,672	19,786
Foreign exchange gain and other	(9)	-	(9)	(2,728)	(2,737)
Cash general and administrative	24,065	26,519	50,584	23,621	74,205
	126,796	78,527	205,323	1,529,355	1,734,678
Earnings before interest, taxes, depletion, depreciation, accretion and other non-cash items	198,445	77,813	276,258	219,631	495,889
Non-cash revenue					
Unrealized gain (loss) on financial derivative instruments	17,299	7,735	25,034	(68,348)	(43,314)
Amortization of loss on financial derivative instruments	-	-	-	-	-
	17,299	7,735	25,034	(68,348)	(43,314)
Other expenses					
Depletion, depreciation and accretion	168,953	31,058	200,011	49,128	249,139
Interest on bank debt	10,082	4,861	14,943	19,723	34,666
Interest and accretion on convertible debentures	5,746	5,828	11,574	12,345	23,919
Amortization of deferred financing charges	956	786	1,742	2,112	3,854
Unrealized foreign exchange loss and other	-	-	-	418	418
Non-cash unit based compensation	4,320	12,476	16,796	6,287	23,083
Internal management charge	(1,280)	1,280	-	-	-
Gain on sale of assets	-	-	-	-	-
Capital taxes	1,314	-	1,314	-	1,314
Current and withholding taxes	(2,124)	3,332	1,208	4,621	5,829
Future income tax (recovery) expense	(56,161)	20,297	(35,864)	1,548	(34,316)
	131,806	79,918	211,724	96,182	307,906
Non-controlling interest - USOGP	-	2,995	2,995	-	2,995
Non-controlling interest - Exchangeables	485	37	522	232	754
Net income for the year	**$ 83,453**	**$ 2,598**	**$ 86,051**	**$ 54,869**	**$ 140,920**

(1) Included in the Midstream Services and Marketing segment is product sales and service revenue of $332.9 million associated with U.S. operations.

	December 31, 2006				
	Canada Oil and Natural Gas Production	United States Oil and Natural Gas Production	Total Oil and Natural Gas Production	Midstream Services and Marketing	Total
Selected balance sheet items					
Capital Assets					
Property, plant and equipment net	$ 1,211,112	$ 380,451	$ 1,591,563	$ 741,974	$ 2,333,537
Intangible assets	-	-	-	193,592	193,592
Goodwill	330,944	-	330,944	100,409	431,353
Capital Expenditures					
Capital expenditures	70,088	54,337	124,425	66,008	190,433
Corporate acquisitions	-	-	-	1,036	1,036
Oil and gas property acquisitions	482,369	(2,012)	480,357	-	480,357
Proceeds from property dispositions	(1,264)	(4)	(1,268)	-	(1,268)
Goodwill additions	-	-	-	2,285	2,285
Working capital					
Accounts receivable	58,250	24,744	82,994	187,141	270,135
Petroleum product inventory	-	-	-	85,868	85,868
Accounts payable and accrued liabilities	86,305	52,626	138,931	156,072	295,003
Long-term debt	$ 217,533	$ 128,542	$ 346,075	$ 642,710	$ 988,785

	Year ended December 31, 2005				
	Canada Oil and Natural Gas Production	United States Oil and Natural Gas Production	Total Oil and Natural Gas Production	Midstream Services and Marketing [1]	Total
Revenue					
Gross production revenue	$ 466,945	$ 154,816	$ 621,761	$ -	$ 621,761
Royalties	(95,403)	(15,019)	(110,422)	-	(110,422)
Product sales and service revenue	-	-	-	908,111	908,111
Realized loss on financial derivative instruments	(48,308)	(16,323)	(64,631)	(2,229)	(66,860)
	323,234	123,474	446,708	905,882	1,352,590
Expenses					
Cost of goods sold	-	-	-	786,564	786,564
Production, operating and maintenance	95,278	39,513	134,791	36,402	171,193
Transportation	5,702	-	5,702	1,230	6,932
Foreign exchange gain and other	(1,815)	(504)	(2,319)	(569)	(2,888)
Cash general and administrative	18,552	11,490	30,042	11,566	41,608
	117,717	50,499	168,216	835,193	1,003,409
Earnings before interest, taxes, depletion, depreciation, accretion and other non-cash items	205,517	72,975	278,492	70,689	349,181
Non-cash revenue					
Unrealized gain (loss) on non-hedging derivative instruments	13,302	(1,910)	11,392	(1,564)	9,828
Amortization of loss on non-hedging derivative instruments	(2,144)	-	(2,144)	-	(2,144)
	11,158	(1,910)	9,248	(1,564)	7,684
Other expenses					
Depletion, depreciation and accretion	155,929	25,553	181,482	11,754	193,236
Interest on bank debt	6,833	2,292	9,125	1,750	10,875
Interest and accretion on convertible debentures	12,342	4,141	16,483	3,160	19,643
Amortization of deferred financing charges	885	297	1,182	227	1,409
Unrealized foreign exchange gain and other	31	10	41	(397)	(356)
Non-cash unit based compensation	2,640	6,098	8,738	1,015	9,753
Internal management charge	(1,695)	1,695	-	-	-
Gain on sale of assets	-	-	-	(5,188)	(5,188)
Capital taxes	4,780	-	4,780	-	4,780
Current and withholding taxes	-	5,628	5,628	-	5,628
Future income tax (recovery) expense	(560)	18,320	17,760	33	17,793
	181,185	64,034	245,219	12,354	257,573
Non-controlling interest - USOGP	-	1,596	1,596	-	1,596
Non-controlling interest - Exchangeables	138	13	151	619	770
Net income for the year	**$ 35,352**	**$ 5,422**	**$ 40,774**	**$ 56,152**	**$ 96,926**

[1] Included in the Midstream Services and Marketing segment is product sales and service revenue of $19.7 million associated with U.S. operations.

	December 31, 2005				
	Canada Oil and Natural Gas Production	United States Oil and Natural Gas Production	Total Oil and Natural Gas Production	Midstream Services and Marketing	Total
Selected balance sheet items					
Capital Assets					
Property, plant and equipment net	$ 634,732	$ 351,073	$ 985,805	$ 716,844	$ 1,702,649
Intangible assets	-	-	-	215,850	215,850
Goodwill	330,944	-	330,944	98,124	429,068
Capital Expenditures					
Property, plant and equipment net	85,402	52,897	138,299	18,200	156,499
Corporate acquisitions	-	91,420	91,420	772,303	863,723
Oil and gas property acquisitions	586	-	586	-	586
Proceeds from property dispositions	45,100	-	45,100	-	45,100
Goodwill additions	-	-	-	98,124	98,124
Working capital					
Accounts receivable	135,220	22,310	157,530	109,716	267,246
Petroleum product inventory	-	-	-	110,638	110,638
Accounts payable and accrued liabilities	176,628	43,243	219,871	89,833	309,704
Long-term debt	$ 238,843	$ 168,075	$ 406,918	$ 477,686	$ 884,604

18. Reconciliation of financial statements to United States generally accepted accounting principles

The consolidated financial statements have been prepared in accordance with accounting principles generally accepted in Canada ("Canadian GAAP"). Any differences in accounting principles as they pertain to the accompanying financial statements are not material except as described below. All adjustments are measurement differences. Disclosure items are not noted.

Consolidated Statements of Earnings - U.S. GAAP

For the year ending December 31, (Cdn$000s)	2006	2005
Net income as reported	$ 140,920	$ 96,926
Adjustments		
Depletion, depreciation and accretion (a)	12,146	13,697
Depletion, depreciation and accretion other (a)	(382,230)	-
FAS 133 adjustment (b)	-	2,144
General and administrative (e)	(483)	(1)
Future income recovery (taxes) (a) (b) (c)	110,898	(5,357)
Accretion on convertible debentures (g)	2,694	2,849
Non-controlling interest - Exchangeable shares (i)	754	770
Net (loss) income – U.S. GAAP	$ (115,301)	$ 111,028
Net (loss) income per unit - basic and diluted	$ (0.59)	$ 0.70

Condensed Consolidated Balance Sheet

As at December 31 (Cdn$ 000s)	2006		2005	
	Canadian	U.S. GAAP	Canadian GAAP	U.S. GAAP
Assets				
Property, plant and equipment (a)	$ 2,333,537	$ 1,906,964	$ 1,702,689	$ 1,646,200
Liabilities and unitholders' equity				
Long-term debt - convertible debentures (g)	285,792	300,110	298,007	315,486
Other long-term liabilities (e)	16,305	16,788	5,019	5,019
Future income taxes (a) (b) (c)	309,006	180,122	91,595	73,609
Non-controlling interest - Exchangeable shares (i)	-	-	8,259	-
Units subject to redemption (h) (i)	-	2,317,196	-	2,236,360
Convertible debentures equity component (g)	18,522	-	19,301	-
Unitholders' contributions (h)	2,254,048	-	1,971,707	-
Cumulative translation adjustment (f)	(42,294)	-	(41,785)	-
Accumulated income (loss)	238,208	(1,044,840)	97,288	(838,253)
Accumulated cash distributions (h)	(926,825)	-	(643,360)	-
Accumulated other comprehensive loss (f)	$ -	$ (43,187)	$ -	$ (42,679)

(a) Under the Canadian cost recovery ceiling test the recoverability of a cost centre is tested by comparing the carrying value of the cost centre to the sum of the undiscounted proved reserve cash flows expected from the cost centre using future price estimates. If the carrying value is not recoverable, the cost centre is written down to its fair value determined by comparing the future cash flows from the proved plus probable reserves discounted at the Trust's risk free interest rate. Any excess carrying value of the assets on the balance sheet above fair value would be recorded in depletion, depreciation and accretion expense as a permanent impairment. Under U.S. GAAP, companies utilizing the full cost method of accounting for oil and natural gas activities perform a ceiling test on each cost centre using discounted future net revenue from proved oil and natural gas reserves discounted at 10 percent. Prices used in the U.S. GAAP ceiling tests are those in effect at year-end and financing and administrative expenses are excluded from the calculation. The amounts recorded for depletion and depreciation have been adjusted in the periods as a result of differences in write down amounts recorded pursuant to U.S. GAAP compared to Canadian GAAP.

In computing its consolidated net earnings for U.S. GAAP purposes, the Trust recorded additional depletion in 2006 of $382.2 million (2005 – nil) and a related future income tax recovery of $114.7 million as a result of the application of the ceiling test. These charges were not required under the Canadian GAAP ceiling tests.

(b) At January 1, 2004, the Trust recorded an unrealized loss of $25.1 million in deferred charges on the consolidated balance sheet that was recognized in income over the term of the previously designated hedged items. For the period ending December 31, 2006, no expenses were recorded (2005 - $2.1 million). Under U.S. GAAP the amortization of the deferred charge has already been captured in prior period accumulated losses.

(c) The Canadian liability method of accounting for income taxes is similar to the United States FAS 109, Accounting for Income Taxes, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been recognized in Provident's financial statements or tax returns. Pursuant to U.S. GAAP, enacted tax rates are used to calculate future taxes, whereas Canadian GAAP uses substantively enacted rates.

(d) The consolidated statements of cash flows and operations and accumulated income are prepared in accordance with Canadian GAAP and conform in all material respects with U.S. GAAP except for the following;
(i) Canadian GAAP allows for the presentation of operating cash flow before changes in non-cash working capital items in the consolidated statement of cash flows. This total cannot be presented under U.S. GAAP.
(ii) U.S. GAAP requires disclosure on the consolidated statement of operations when depreciation, depletion and amortization are excluded from cost of goods sold. This disclosure has not been noted on the face of the consolidated statement of operations.

(e) Under Canadian GAAP, Provident follows CICA handbook section 3870 "Stock-based compensation and other stock-based payments" which provides for the presentation and measurement of cash-settled unit-based compensation as liabilities based on the intrinsic value each period. Under U.S. GAAP FAS 123R "Share-based payments", public entities are required to measure liability awards based on the award's fair value remeasured at each reporting date until the date of settlement. Under U.S. GAAP, Provident measures the fair value of such liability awards using a binomial option pricing model at each reporting date until the date of settlement. Compensation cost for each period is based on the change in the fair value of the units for each reporting period and is recognized over the vesting period.

(f) U.S. GAAP requires gains or losses arising from the translation of self-sustaining operations to be included in other comprehensive losses. Canadian GAAP requires these amounts to be recorded in unitholders' equity.

(g) Under Canadian GAAP Provident applies CICA Handbook Section 3861 ("HB 3861") "Financial Instruments - Presentation and Disclosure" for financial instruments that may be settled at the issuer's option in cash or its own equity. Under U.S. GAAP, the convertible debentures are disclosed as long-term debt at their face value versus Canadian GAAP that requires discounting of the convertible debentures, accretion expense to represent the unwinding of the discounted convertible debentures and a value assigned within equity to the conversion feature component of the convertible debentures.

(h) Under U.S. GAAP, a redemption feature of equity instruments exercisable at the option of the holder requires that such equity be excluded from classification as permanent equity and be reported as temporary equity at the equity's redemption value. Changes in redemption value in the period are charged to accumulated earnings. Under Canadian GAAP, such equity instruments are considered to be permanent equity and are presented as unitholder's equity. The Trust's units and exchangeable shares both have a redemption feature, which qualify them to be considered under this guidance.

(i) Under Canadian GAAP, the Trust's exchangeable shares were classified as non-controlling interest. As these exchangeable shares could be converted into trust units at the option of the holder, the exchangeable shares were classified as units subject to redemption along with the trust units for U.S. GAAP purposes. In 2006, all of the outstanding exchangeable shares were converted into Provident Trust units

Recent U.S. Accounting Pronouncements

Accounting for certain hybrid financial instruments

In March 2006 the FASB issued FAS 155, "Accounting for Certain Hybrid Financial Instruments". FAS 155 permits fair value re-measurement for any hybrid financial instrument that contains an embedded derivative that otherwise would require bifurcation, clarifies which interest-only and principal-only strips are not subject to FAS 133, establishes a requirement to evaluate interests in securitized financial assets to identify freestanding derivatives or instruments that are considered hybrid financial instruments, clarifies that concentrations of credit risk in the form of subordination are not embedded derivatives and eliminates the prohibition on qualifying special-purpose entities holding a derivative financial instrument that pertains to a beneficial interest other than another derivative financial instrument. This statement is effective for all financial derivative instruments acquired after September 13, 2006. The adoption of this statement has not had a material impact on the Trust's consolidated financial statements.

Accounting for servicing of financial assets

In March 2006, FAS 156, "Accounting for Services of Financial Assets" was issued as an amendment to FAS 140. The revisions clarify when a servicer should separately recognize servicing assets and servicing liabilities, indicates that separately recognized servicing assets and liabilities should initially be measured at fair value and allows for subsequent measurement of the assets and liabilities to be conducted under the amortization method or the fair value measurement method. FAS 156 is effective for fiscal years beginning after September 15, 2006. The Trust does not expect the adoption of this statement to have a material impact on its financial statements.

Accounting for uncertainty in income taxes

In July 2006, the FASB issued FIN 48, "Accounting for Uncertainty in Income Taxes". The interpretation creates a single model to address uncertainty in tax positions and clarifies the accounting for income taxes by prescribing the minimum recognition threshold a tax position is required to meet before being recognized in the financial statements. The statement also provides guidance on de-recognition, measurement, classification, interest and penalties, accounting in interim periods, disclosures and transitions as well as specifically scopes out accounting for contingencies. FIN 48 is effective for fiscal years beginning after December 15, 2006. The Trust is currently evaluating the effect that this interpretation might have on the Trust's financial statements.

Accounting for conditional asset retirement obligations

In 2005, FASB issued Financial Interpretation 47 "Accounting for Conditional Asset Retirement Obligations". This interpretation clarifies that the term conditional asset retirement obligation as used in FAS 143 "Accounting for Asset Retirement Obligations" refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and/or method of settlement. Thus, the timing and/or method of settlement may be conditional on a future event. Accordingly, an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated. This interpretation is effective no later than the end of fiscal years ending after December 15, 2005. The adoption of this statement has not had a material impact on the Trust's consolidated financial statements.

Accounting changes and error corrections

In 2005, FASB issued FAS 154 "Accounting Changes and Error Corrections" which replaces APB Opinion 20. This statement changes the requirements for the accounting and reporting of a change in accounting principle. FAS 154 requires retrospective application of voluntary changes in accounting principles to prior period financial statements, unless it is impracticable to do so. The statement is effective for fiscal years beginning after December 15, 2005. The adoption of this statement has not had a material impact on the Trust's financial statements.

Exchange of non-monetary assets

In 2004, FASB issued FAS 153 "Exchange of Non-monetary Assets". This statement is an amendment of APB Opinion No. 29 "Accounting for Non-monetary Transactions". Based on the guidance in APB Opinion No. 29, exchanges on non-monetary assets are to be measured based on the fair value of the assets exchanged. Furthermore, APB Opinion No. 29 previously allowed for certain exceptions to this fair value principle. FAS 153 eliminates APB Opinion No. 29's exception to fair value for non-monetary exchanges of similar productive assets and replaces this with a general exception for exchange of non-monetary assets that do not have commercial substance. For purposes of this statement, a non-monetary exchange is defined as having commercial substance when the future cash flows of an entity are expected to change significantly as a result of the exchange. The provisions of this statement are effective for non-monetary asset exchanges that occur in fiscal periods beginning after June 15, 2005 and are to be applied prospectively. Earlier application is permitted for non-monetary asset exchanges that occur in fiscal periods beginning after the issue date of this statement. The adoption of this statement has not had a material impact on the Trust's financial statements.

This page is left blank intentionally

This page is left blank intentionally

Board of Directors

John B. Zaozirny, Q.C. [2]
Chairman
Calgary, Alberta

Thomas W. Buchanan, CA
Calgary, Alberta

Randall J. Findlay, P.Eng.
DeWinton, Alberta

Grant D. Billing, CA [2]
Calgary, Alberta

Hugh A. Fergusson, LLB [1][3]
Calgary, Alberta

Norman R. Gish, LLB [2]
Calgary, Alberta

Bruce R. Libin, Q.C. [1][3]
Calgary, Alberta

Robert W. Mitchell, Ph.D. [3]
Calgary, Alberta

Byron J. Seaman, D.Sc. [3]
Calgary, Alberta

Mike H. Shaikh, CA [1]
Calgary, Alberta

Jeffrey T. Smith, P.Geol. [2][3]
Calgary, Alberta

[1] Member of Audit Committee

[2] Member of Governance, Human Resources and Compensation Committee

[3] Member of Reserves, Operations and EH&S Committee

Officers

Thomas W. Buchanan, CA
Chief Executive Officer and President

David I. Holm, B.Comm., LLB
Executive Vice President, Strategy, Finance, Business Development and Corporate Secretary

Daniel J. O'Byrne, P.Eng., MBA
Executive Vice President, Operations and Chief Operating Officer

Murray N. Buchanan, MBA
Co-President, Midstream Business Unit

Andrew G. Gruszecki, MBA
Co-President, Midstream Business Unit

Gary R. Kline
Senior Vice President, Commercial Development and Risk Management

Lynn M. Rannelli
Assistant Corporate Secretary

Cameron G. Vouri, P.Eng.
President, Canadian Oil and Gas Production Business Unit

Mark N. Walker, C.M.A.
Senior Vice President, Finance and Chief Financial Officer

Banking Syndicate

Lead Syndicate Members (Canada)
National Bank of Canada
Bank of Nova Scotia
Bank of Montreal
The Toronto Dominion Bank

Lead Syndicate Members (U.S.)
Wells Fargo Bank

Engineering Consultants

McDaniel & Associates Consultants Ltd
Netherland, Sewell & Associates, Inc
AJM Petroleum Consultants

Auditors

PricewaterhouseCoopers LLP

Legal Counsel

Macleod Dixon LLP

Trustee

Computershare Trust Company of Canada

Stock Exchanges

Toronto Stock Exchange
Units: PVE.UN
Debentures: PVE.DB.A
PVE.DB.B
PVE.DB.C
PVE.DB.D

New York Stock Exchange
Units: PVX

Contact Information

For Investor Relations Inquiries:

Laurie Stretch, MA
Senior Manager, Investor Relations and Communications
Phone: (403) 231-6710
info@providentenergy.com

800, 112 – 4 Avenue SW
Phone: (403) 296-2233

Calgary, Alberta T2P 0H3
Toll Free: (800) 587-6299

www.providentenergy.com
Fax: (403) 294-0111

PROVIDENT
ENERGY TRUST